CALIFORNIA
ENERGY COMMISSION

Energy Research and Development Division

**FINAL PROJECT REPORT**

# Station Automation and Optimization of Distribution Circuit Operations

**Gavin Newsom, Governor**
**March 2020 | CEC-500-2020-022**

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**Contract Number**: EPC-15-086

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# ACKNOWLEDGEMENTS

The authors thank project partners OPAL-RT technologies and Southern California Edison for their efforts and inputs to this project.

# PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

*Station Automation and Optimization of Distribution Circuit Operations* is the final report for the Station Automation and Optimization of Distribution Circuit Operations project (Contract Number CEC-EPC-15-086) conducted by Advanced Power and Energy Program, University of California Irvine. The information from this project contributes to the Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the Energy Commission at 916-327-1551.

# ABSTRACT

The University of California, Irvine's Advanced Power and Energy Program used results, insights, and capabilities from the Irvine Smart Grid Demonstration and Generic Microgrid Controller projects to enhance substation control and distribution system management. The project implemented a generic microgrid controller at a substation to facilitate (1) maximizing the penetration of distributed energy resources, (2) assessing the viability of a retail/distribution electricity market, (3) developing strategies for a better distribution system management and use of smart grid technologies, and (4) simulating and assessing deployed fuel cells at the substation.

The research team used generic microgrid controller specifications to develop a controller for simulation of two 12 kilovolt distribution circuits at a distribution substation. The circuits and the controller were simulated using an OPAL-RT simulation platform. The results of the simulations were then used to determine the benefits of the distributed energy resources dispatched by the controller simulated at the substation.

Results of the simulation show that using a controller at the substation facilitates an increase in the renewable penetration and associated reduction in greenhouse gas emissions. Larger batteries on the utility side result in higher renewable penetration at a lower cost compared to residential storage on the customer side. Circuit battery and demand response can alleviate the "duck curve," fuel cell deployment at the substation increases reliability significantly, and retail customer participation in a distribution electricity market can reduce customer energy bills.

**Keywords**: Substation, automation, distribution system management, distribution system control, distributed energy resources, controller

Please use the following citation for this report:

Razeghi, Ghazal, Jennifer Lee, Scott Samuelsen. Advanced Power and Energy Program. 2020. *Station Automation and Optimization of Distribution Circuit Operations*. California Energy Commission. Publication Number: CEC-500-2020-022.

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# EXECUTIVE SUMMARY

## Introduction

California's Renewables Portfolio Standard goals include powering 44 percent of the state's electricity using renewable resources by 2024, 52 percent by 2027, 60 percent by 2030, and 100 percent by 2045. Distributed energy resources—defined in Public Resources Code Section 769 as distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies—can help achieve these renewable energy goals. However, integrating these resources into the grid requires upgrades to the electricity distribution system to handle high levels of distributed and renewable energy resources, increase grid reliability, and reduce the frequency and duration of outages.

New research concepts and technologies are under development in the energy and smart grid fields with the goals of increased efficiency, reduced emissions, and enhanced controllability. Many of these are being installed on 12 kilovolt (kV) distribution circuits leading from utility substations. Examples include dispatchable loads and generation (that can be controlled and adjusted through a controller and energy management system) and other smart distributed energy resources along with intermittent renewable power generation such as solar or wind. To manage these resources and assure the reliability and resiliency of the circuit and the facilitation of electricity markets, utility substations may benefit from using controllers and optimized dispatch control strategies.

## Project Purpose

The goal of this project was to simulate the use of a generic microgrid controller specification at a utility substation to determine whether it could enhance utility substation capabilities, control secondary circuit assets as a single unit, and improve the distribution system management.

The objectives of this strategy include:

1. Maximizing the penetration of renewable resources and distributed energy resources on the substation distribution circuits.
2. Developing and accessing the viability of a retail electricity market.
3. Developing strategies for better distribution system management and use of smart grid technologies.
4. Simulating and assessing the deployment of fuel cells at the substation.

This project addresses funding initiatives in the CEC's Electric Program Investment Charge Investment Plan to "develop controls and equipment to expand distribution automation capabilities" and "develop automation and operational practices to make use of smart grid technologies."

This project also supports California's efforts to promote distributed energy resources. Assembly Bill 2514 (Skinner, Chapter 469, Statutes of 2010) encourages utilities to incorporate energy storage into the grid to help support the integration of renewable energy resources and defer the need for new fossil-fueled power plants and transmission and distribution infrastructure. Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013) defines distributed energy resources and requires investor-owned utilities to file distribution resource plans that identify optimal locations for the deployment of distributed resources.

By addressing the issue of locating distributed energy resources, including energy storage, and by assessing a variety of tariffs through implementing and simulating various scenarios, this project addressed the requirements in AB 2514 and AB 327. By simulating a controller at the substation to control the distributed energy resources including power generation, energy storage, and controllable loads, the distributed energy resource assets are used to their fullest potential and their negative impacts are mitigated. The project also contributes to the Renewables Portfolio Standard goals by helping integrate renewable resources into the grid. The method is designed to identify and address negative issues associated with renewable resources in the distribution system, and thus increase and manage the penetration of these resources.

## Project Approach

In this project, the research team systematically evaluated the deployment of controllers with optimized dispatch control strategies. The project leveraged two previous U.S. Department of Energy projects, (1) the Generic Microgrid Controller project, and 2) the Irvine Smart Grid Demonstration project. Data collected from the Irvine Smart Grid Demonstration project were used to validate the models and inform the design and operation of distributed energy resources. For analysis, the research team selected two 12kV distribution circuits coming from a Southern California Edison substation, the same two circuits associated with the Irvine Smart Grid Demonstration project. The controller and the system under study were simulated on OPAL-RT.

The research included evaluating various scenarios to assess the effects of:

1. Next-generation grid management at the distribution level.
2. Deployment of generating resources such as fuel cells at the substation.
3. Smart grid technologies on reducing required upgrades to the system.
4. increasing the penetration of distributed energy resources including intermittent renewables, residential energy storage units, and community energy storage.
5. Enhancing the resiliency of the community by increasing reliability of the electricity grid and reducing customer outages.

Moreover, the research team analyzed tariffs and interconnection agreements to identify and assess available opportunities for distributed energy resources to participate in markets and identify necessary changes to help integrate distributed energy resources into the grid in the future, and a possibility of distribution/retail markets.

The project was led by the Advanced Power and Energy Program and a team that included Southern California Edison, OPAL-RT, and Power Innovation Consultants. The project included a technical advisory committee composed of Southern California Edison, the California Independent System Operator, Schweitzer Engineering Laboratories, and Emerson Automation Solutions. The team implemented recommendations from the technical advisory committee throughout the project.

## Project Conclusions

The conclusions of the project are:

- Higher penetration of distributed energy resources (including photovoltaics [PV]) can be achieved with substation control and automation. Results of the simulations demonstrated that using the controller to optimally manage the operation of distributed energy resources in distribution circuits increases the PV hosting capacity of the distribution system without needing upgrades. The addition of energy storage units and making the best use of their operation can further increase PV penetration in the distribution system, as demonstrated by the results of the residential energy storage units and community energy storage simulations.
- Community energy storage is a more economic approach for achieving high PV penetration and GHG reduction than residential storage. Residential energy storage and community energy storage cases simulated and assessed in this project resulted in similar PV penetration (37.5 percent and 35.4 percent, respectively). However, using community energy storage units, the PV penetration required about 50 percent less battery energy storage in terms of power and energy capacity. This result represents a more economic approach since battery energy storage is capital intensive. The residential energy storage case, with more energy storage and slightly higher PV penetration, provides more greenhouse gas emission reductions (34 percent versus 32 percent for community energy storage). However, the residential energy storage cases result in 355 million tonnes carbon dioxide equivalent ($mTCO_2e$) reduction per megawatt-hour (MWh) of installed energy storage, while the community energy storage cases result in 660 $mTCO_2e$ reduction per MWh of installed energy storage. This result demonstrates that the community energy storage approach is superior in terms of greenhouse gas reduction and cost, mainly because residential energy storage is located behind the meter and owned by the customers, and thus is operated primarily to benefit the customer first, followed by the grid.
- Distributed energy resources can serve the needs of the larger grid. Although distributed energy resources mainly serve the local needs of the distribution

system, they can be used to serve the needs of the larger grid. The results of the simulations showed that a megawatt-class battery installed at the distribution substation helps curb PV export to the grid. Demand response, on the other hand, helps reduce demand later in the afternoon and the need for high ramping rates during these times.

- Fuel cell deployment at the substation improves reliability of the system. As demonstrated by the results of the simulations, a source of firm power at the substation helps better manage supply and demand, and reduce unserved load during grid outages. This results in significant improvement of the System Average Interruption Duration Index and System Average Interruption Frequency Index of the system.
- Participation in the distributed energy resource market benefits the grid as well as the resource owner or aggregator. The team's cost-benefit analysis showed that overall market participation increases the benefit-to-cost ratio of distributed energy resources, making them more attractive to investors. The extent of the benefits and the most lucrative markets for distributed energy resources depend on the size, location, and ownership of the resource. For example, for behind-the-meter residential energy storage owned by a residential customer, most energy resource benefits were associated with retail load-shifting and frequency regulation. However, for a battery installed at a substation—which is much larger than a residential energy storage unit and on the utility side of the meter—the benefits are associated with wholesale day-ahead market participation, non-spinning reserve, and well as frequency regulation. Both of these resources are able to serve the grid needs since they can be cleared and provide services in various wholesale markets.
- Retail customer participation in distribution electricity markets can provide financial benefits. By directly participating in a distribution market, retail customers will see real-time electricity market prices and be able to respond to those prices to reduce their overall energy bill. Simulation results confirmed that this distribution and retail market can reduce retail customer electricity bills.

## Technology/Knowledge Transfer

The project team made the results of the simulations and analysis in the project available to the public and decision makers in several ways (and will continue to do so in the future) in the following ways:

- Publishing the results in journal articles and conference proceedings,
- Presenting the results to visitors to the Advanced Power and Energy Program and recipients of the annual Advanced Power and Energy Program annual report, Bridging,
- Summarizing the results at conference presentations, association meetings, meetings with policy makers, and meetings with other stakeholders.

## Conferences

- Dr. Razeghi made a presentation on retail and distribution markets associated with the project at the Colloquium on Environmentally Preferred Advanced Generation 2018. Professor Samuelsen has also regularly featured the project in presentations, including in a short course in summer 2018 for managers of the Korea Electric Power Corporation.
- Representatives of the Advanced Power and Energy Program will participate in various conferences discussing the results and outcomes of the project with academia, industry, and policymakers. These conferences include the U.S. Department of Energy Microgrid Contractors Meetings and the annual International Colloquium on Environmentally Preferred Advanced Generation hosted by the Advanced Power and Energy Program.

## Publications

The project team will submit results and lessons learned from the project to journals for peer-review and publication in engineering journals such as *Energy*, *Applied Energy*, and *Journal of Power Source*. Journal articles are available through university libraries, ProQuest, and eScholarship (open access publications from the University of California).

The Advanced Power and Energy Program publishes "Bridging," an annual magazine featuring projects, students' accomplishment, and publications. The magazine is widely circulated throughout California and the nation, and this project will be featured in the 2020 issue, focusing on the results and lessons learned from this project.

Dissemination of information and results of this project will benefit from the unique position the Advanced Power and Energy Program holds between academia, industry, and government. Advanced Power and Energy Program formed partnerships with leaders in the automotive, power generation, power distribution, and aerospace industries. In doing so, synergistic relationships have formed in which the lag time between research findings and applications is minimized. This attribute is built on the Advanced Power and Energy Program's philosophy of a unique combination of "bridging" from engineering science to practical application, and a sustained engagement of industry, utilities, government agencies, national laboratories, and academic institutions.

# Benefits to California

The project has several benefits to the state of California as well as ratepayers:

- Reduced costs: Using a controller at substations for economic dispatch increases the efficiency of the operation and thus reducing costs. Furthermore, using distributed energy resources avoids delivery losses estimated to be 6 percent in California. Using distributed energy resources reduces electricity demand and fossil fuel use, and thus costs. Controls that allow distributed energy resources to participate in market opportunities and future distribution markets benefits customers financially and reduces overall electricity cost. Moreover, improvements in system reliability reduce financial losses from power outages.

- Reduced emissions: Increased use and penetration of solar PV achieved in this project considerably reduced emissions, including greenhouse gas emissions, depending on the distributed energy resource scenario, type, and penetration.
- Improved reliability: Moving from centralized generation to distribution generation can increase the reliability of serving loads. In this project, using a fuel cell and distributed energy resources improved the System Average Interruption Duration Index (a reliability indicator used by electric utilities) as much as 60 percent, assuming that the distributed energy resources were able and allowed to operate during an outage.
- Other benefits: Other benefits of the project include increased safety, energy security, enhanced and improved resiliency, reduced renewable portfolio standard procurement, reduced electricity demand, reduced use of fossil fuels, and avoided (or deferred) transmission and infrastructure upgrade costs.

## Recommendations

- Conduct further research on transition to an islanded mode operation and resynchronization. Emergency cases, while studied in this project, focused on balancing supply and demand without any electricity import from the grid.
- Conduct further study on the use of fuel cells in system restoration and recovery, including a detailed analysis of fuel cell operation in grid-forming.
- Standardize, simplify, and streamline he process for interconnection agreements and allow export of electricity to the grid to provide more economic benefit to customers than allowed under existing net-metering rules.
- Allow distributed energy resources to export and sell the electricity to the utility, independent system operator markets, or retail customers.
- Rethink anti-islanding requirements and allow for intentional islands.
- Establish independent system operator products specific to distributed energy resources and microgrids to enable distributed energy resources with direct and indirect benefits to be included in the bid.
- Pursue legislation to establish competitive distribution and retail markets, which requires more research on the impact of such markets in long term on prices.

# CHAPTER 1: Introduction

New research concepts and technologies are under development in the energy and smart grid field with the goals of increased efficiency, reduced emissions, and enhanced controllability. With the breadth of studies being conducted within the distributed generation and smart grid arena, it is important that policy makers, engineers, energy professionals, building owners, and investors be made aware of the status and results of the state-of-art research that is being conducted in this field.

The future indicated 12 kilovolt (kV) distribution circuits emanating from utility substations that are comprised of dispatchable loads, dispatchable generation, and other smart distributed energy resources along with intermittent renewable power generation. Substations require optimized dispatch control strategies to manage these resources and assure both (1) reliability and resiliency of the circuits, and (2) the facilitation of electricity markets.

The goal of this project was to establish the substation control capabilities necessary to manage distributed energy assets as a single unit in the context of high penetration of renewable generation and the emergence of electricity markets. To achieve this goal, the objectives of this project were to:

- Maximize the penetration of renewable resources and distributed energy resources.
- Develop and assess viability of a retail electricity market.
- Develop strategies for a better distribution system management and use of smart grid technologies.
- Simulate and assess the deployment of fuel cells at the substation.

In this project, the Generic Microgrid Controller (GMC) software specifications, established under a U.S. Department of Energy (USDOE) program, were used to develop a controller which is simulated on two 12kV distribution circuits at a Southern California Edison (SCE) substation using OPAL-RT. The two circuits were previously part of the recently completed USDOE Irvine Smart Grid Demonstration (ISGD) project led by SCE and with APEP as the research partner and project host.

## Project Tasks

The project included the following tasks:

### Task 1: General Project Tasks

This task included all the activities required to control the cost, schedule, and risk of the project. Preparation and submission of the required reports including the final report was also monitored under this task.

### Task 2: Base Model Development

The goal of this task was to develop detailed models of the utility substation and the two 12-kV circuits under study. To this end, OPAL-RT hardware and software were obtained and the system was modeled in OPAL-RT (ePhasorSim). The ISGD project blocks were modeled in detail in the circuit. The Zero Net Energy (ZNE) block was modeled as a smart-home to achieve zero net energy with 4kW rooftop solar photovoltaic (PV) panels and 4kW/10kWh battery storage along with electric vehicle charging equipment and other various dispatchable loads (such as HVAC and smart appliances including smart fridge). Also the Residential Energy Storage Unit (RESU) block and the Community Energy Storage (CES) block were modeled with the same equipment but with 4kW/10kWh battery storage in each home for the RESU block and a 25kW/50kWh battery near the distribution transformer for 9 homes of the CES block. The load associated with the ZNE block was adjusted to reflect the energy efficiency measures implemented in these homes.

### Task 3: Scenario Development

The goal of this task was to develop a set of future viable scenarios to be assessed using the models and GMC developed. The scenarios developed covered:

- The various technologies to be added as DER to the circuits under study
- The various smart grid technologies to further enhance controllability of the assets
- The demand response strategies to further optimize the operations
- The maximum DER/renewable penetration that the circuits can handle
- The impacts of DER on the distribution circuit if the maximum penetration is surpassed
- Viable future scenarios to be further assessed using modeling

The four group of scenarios included: 1) high renewable penetration, 2) energy storage, 3) demand response, and 4) circuit independent. In the first group, the maximum PV hosting capability of the circuits was determined by taking into account both electrical constrains of the system as well as available rooftop spaces and footprint for PV installation. In the second group, the impact of addition of various types of energy storage was determined on the operation of the circuit and hosting capability. In the third group, demand response and load management was added to the models. And in the last group, the capabilities of the distribution circuits in serving the loads in the absence of the grid were assessed.

## Task 4: Controller Development

The goal of this task was to develop a controller for the system under study based on the GMC specification and simulate the controller operation in the scenarios previously developed. To this end, the GMC specifications were used to determine the controller requirements and overall architecture, the controller was then implemented into and tested using OPAL-RT, and the scenarios previously developed were assessed and analyzed with this controller simulated at the substation.

The controller at the substation was designed to send signals to the device controllers based on an economic dispatch, and set the *mode* of operation. The details of the operation were then determined by the device controllers, giving (1) the DERs a level of autonomy, (2) the customers a level of visibility to determine the details of operation, and (3) the utility or grid operator access to the DER as a controllable entity.

The batteries had a local (device) control mechanism built in as a model and operated as either (1) residential energy storage units (RESUs) with PV-capture and time-base load shifting modes, or (2) community energy storage (CES) with permanent load-shifting and load-limiting modes.

The fuel cell located at the substation for resiliency and reliability operated in a base-loading or load-following mode determined by the controller.

The demand response signal was sent by the controller to the loads' local controller based on the utility request or the need to balance load and generation. Load controllers included the local controller on electric vehicle service equipment (EVSEs) associated with plug-in electric vehicles (PEVs) and customers' energy management systems (EMSs).

## Task 5: Retail/Distribution Market

The goal of this task was to assess various tariffs and interconnection agreements, and to develop the basics of a retail/distribution electricity market. To this end a detailed analysis was performed regarding current tariffs and interconnection agreements associated with DERs. The limitations and shortcomings of such tariffs were analyzed, as well as an overview of the CAISO market structure and products that allow aggregation and participation of DERs in various markets. A cost/benefit analysis was performed to assess the benefit of market participation for various types of DERs studied in this project.

The fundamentals of electricity markets and the basic design for a Distribution System Operator (DSO) and its role as well as DSO/ISO interaction were established and, using this design, the benefits of distribution market participation for retail customers were analyzed.

Benefit-cost analysis was performed to assess the overall benefits of electricity market participation for DERs owned by the utility and those behind the meter. This analysis also included participation of retail customers in future distribution markets.

### Task 6: Evaluation of Project Benefits

Using the outcomes of the simulations, the benefits of the project in terms of reduced costs and emissions, and increased reliability were determined as well as some qualitative benefits such as increased safety

### Task 7: Technology/Knowledge Transfer Activities

The goal of this task was to ensure that the results and lessons learned from this project are available to public and stakeholders. This was accomplished through publishing reports and article, presenting at conferences, and engaging industry, policy makers and other stakeholders.

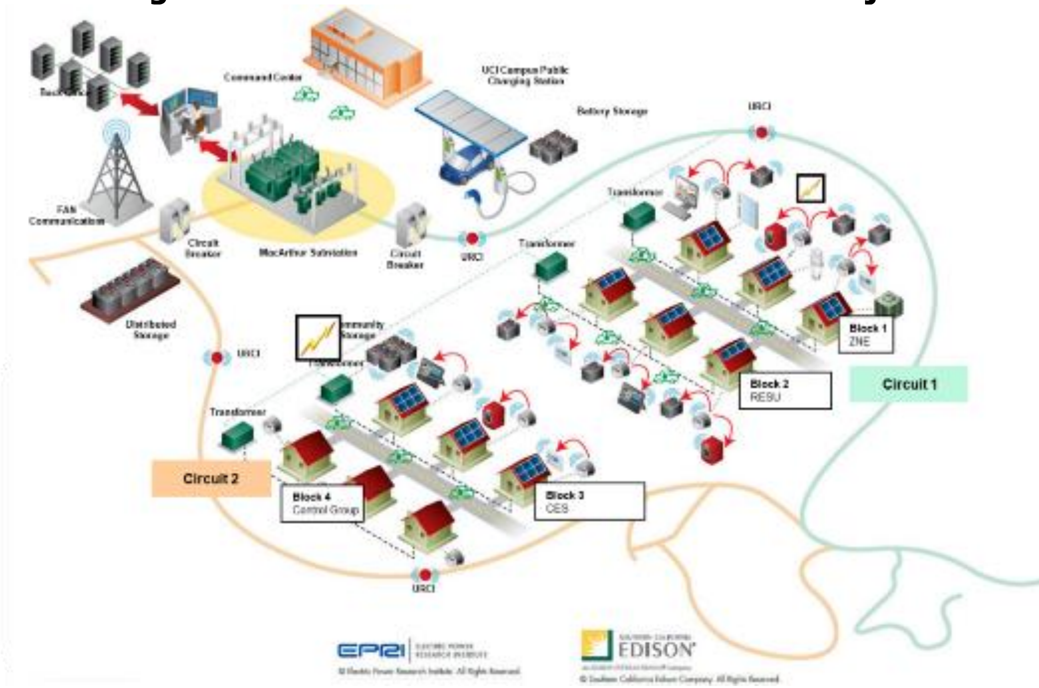
## Irvine Smart Grid Demonstration Project

The site associated with the ISGD included thirty homes equipped with solar PV, smart appliances, smart meters, community energy storage, and plug-in electric vehicles. These homes were distributed in the following four blocks, each with an individual transformer:

1. ZNE (Zero Net Energy) block. In this block, homes were outfitted with energy efficiency upgrades, devices capable of demand response, a Residential Energy Storage Unit (RESU), a solar array, and a plug-in electric vehicle (PEV).
2. RESU block. The homes in this block were identical to ZNE block except for the energy efficiency upgrades.
3. CES (Community Energy Storage) block. This block was identical to the RESU block, but instead of each home having its own RESU, a community energy storage served the entire block.
4. Control block. These homes served as the control group with no modification. A schematic of the homes is shown in Figure 1.

During the ISGD project, various tests were performed from demand response, to testing the energy storage in various modes, to smart charging of electric vehicles. For these homes, almost 2 years of data (depending on the data type) were acquired including detailed load data. Nearly all the individual loads and major appliances were sub-metered and recorded along with charge/discharge data associated with energy storage in various modes, PV data, weather data, transformer data, and EV data. Details of the data collected and tests performed in the ISGD project can be found in the project final report available at:
https://energy.gov/sites/prod/files/2017/01/f34/ISGD%20Final%20Technical%20Report_20160901_FINAL.pdf

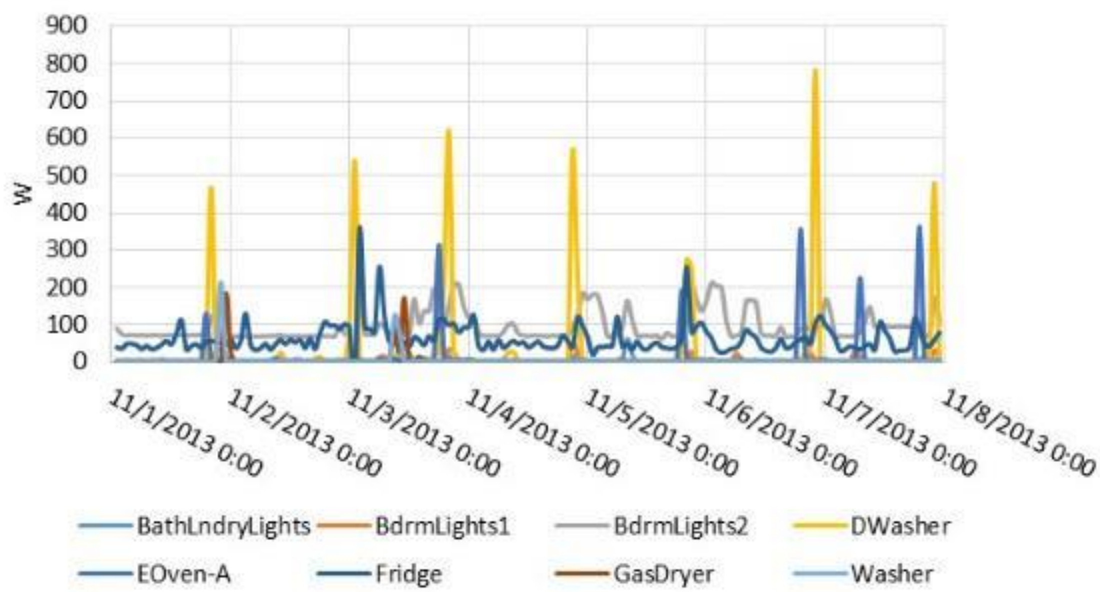
**Figure 1: Irvine Smart Grid Demonstration Project**




Source: Southern California Edison and Electric Power Research Institute

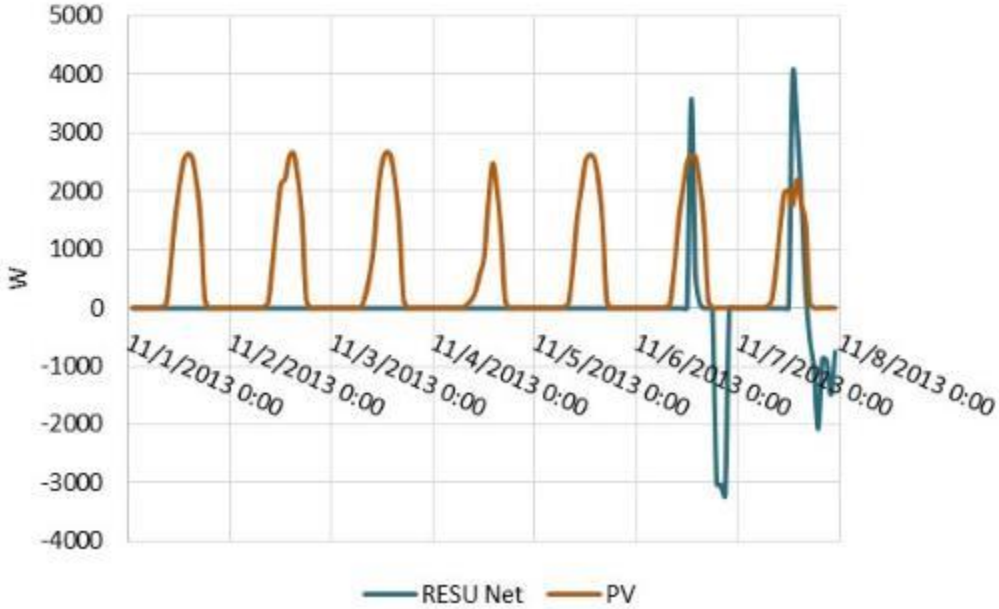
Figure 2 provides an example of the data. The data shown are associated with one week in November for a representative home in the ZNE block. Note that the data shown do not include all the sub-metered loads in this home. PV generation and battery operations for the same home are shown in Figure 3. Data associated with the EVs are shown in Figure 4 for June 2014.

**Figure 2: Load Sample of Home in Zero Net Energy Block**



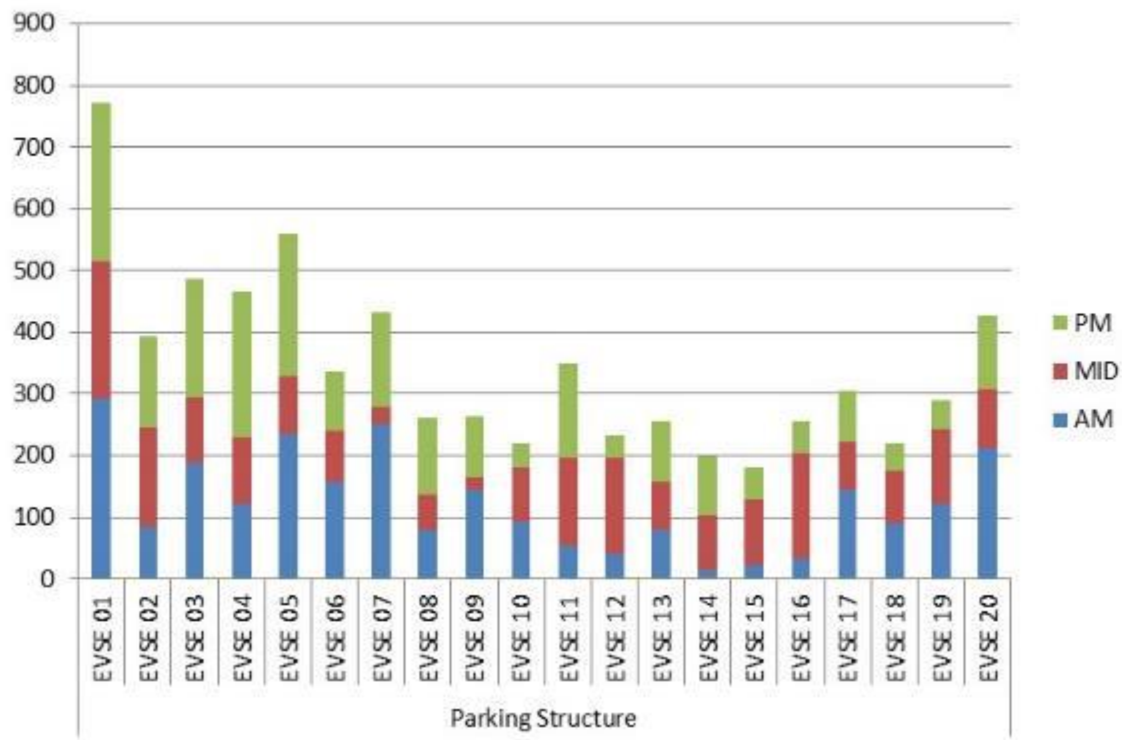

Source: UC Irvine

**Figure 3: Photovoltaic and Residential Energy Storage Unit Sample Data for Home in ZNE Block**




Source: UC Irvine

**Figure 4: Electric Vehicle Data for June 2014**




Source: UC Irvine

## Generic Microgrid Controller

The main objective of the generic microgrid controller (GMC) project was to design a controller that will facilitate the deployment of microgrids, be easily adapted to various microgrid configurations, and reduce up-front engineering costs associated with the design and development of microgrid controllers. The overarching goal of the GMC project was to establish controller software specifications that:

- Provide a control structure amenable to accommodating an array of microgrid configurations and a portfolio of functional requirements.
- Possess a high level architecture that can readily be adopted by commercial suppliers.
- Support unlimited nesting of conforming microgrid control schemes.
- Integrate into a full-featured Energy Management System (EMS) as a module, and
- Provide the following features:
    - Seamless islanding and reconnection of the microgrid.
    - Efficient, reliable, and resilient operation of the microgrid with the required power quality, whether islanded or grid-connected.
    - Existing and future ancillary services to the larger grid.
    - The capability for the microgrid to serve the resiliency needs of participating communities.
    - Communication with the electric grid utility as a single controllable entity.
    - Increased reliability, efficiency and reduced emissions.

A select set of microgrids, operating a variety of microgrid configurations, served as "collaborating microgrid partners" in the project and assured thereby that the GMC developed under this program can readily be applied to microgrids of different sizes, and equipped with various resources, attributes, and equipment. Collaborating microgrid partners included the UCI Medical Center), the Port of Los Angeles, Port of Long Beach, and the Irvine Ranch Water District.

The objectives of the GMC project were achieved in two phases: (Phase I) Research, Development and Design (Design), and (Phase II) Testing, Evaluation, and Verification (TEV). In Phase I, specifications were developed for the GMC and a detailed test plan was established to test the functional requirements of the GMC. The GMC addresses two core functions, transition and dispatch, as well as several optional higher level functions such as economic dispatch, and renewable and load forecasting.

For the purposes of Phase II (TEV), the GMC was applied to two microgrids: (1) the 20 MW-class UCI Microgrid (UCIMG), and (2) the 10MW-class UCI Medical Center Microgrid (UCIMC) using a commercially viable platform (ETAP). Both microgrids and their components were modeled using the Simulink platform and run on an advanced real-time OPAL-RT hardware-in-the-loop (HIL) simulator. Model simulation results were used to further inform the development of a controller designed for uninterrupted operation of the microgrid through events including islanding, reconnection, and internal/external faults. The simulations demonstrated proof-of-concept, identified the system's operational limits, and anchored a test plan for an islanding demonstration of the UCIMG.

Once the performance of the GMC was established and tested in HIL, the TEV expanded to include field testing at the UCIMG. UCIMG was then islanded for 75 minutes for a field demonstration which required coordination with UCI Facilities Management, the UCI Administration, the UCI Office of Design and Construction, the local utility partner (Southern California Edison), the manufacturer of the UCIMG Co-Gen (Solar Turbines), and Schweitzer Engineering Laboratories (SEL). During the 75-minute islanded operation, step loads were added including three 200hp pumps and campus building loads. In addition, a 500 kW chiller was dropped from the load at approximately 60-minutes into the excursion. The islanding test demonstrated the ability of the UCIMG to disconnect from the grid and island, operate in islanded mode under conditions of load changes, and resynchronize and reconnect to the larger grid.

The two major products of this project were (1) specifications[1,2] for a GMC to facilitate standardization and integration of microgrids, and (2) a successful islanding demonstration of a community microgrid.

The GMC has two major functions (transition and dispatch) as shown in Figure 5 which also depicts three levels of control. In this project, the controller adopts the dispatch function for the two utility 12 kV distribution circuits and, when controlled as single entities, each circuit is tantamount to a microgrid except for seamless transitions to and from an islanded mode.

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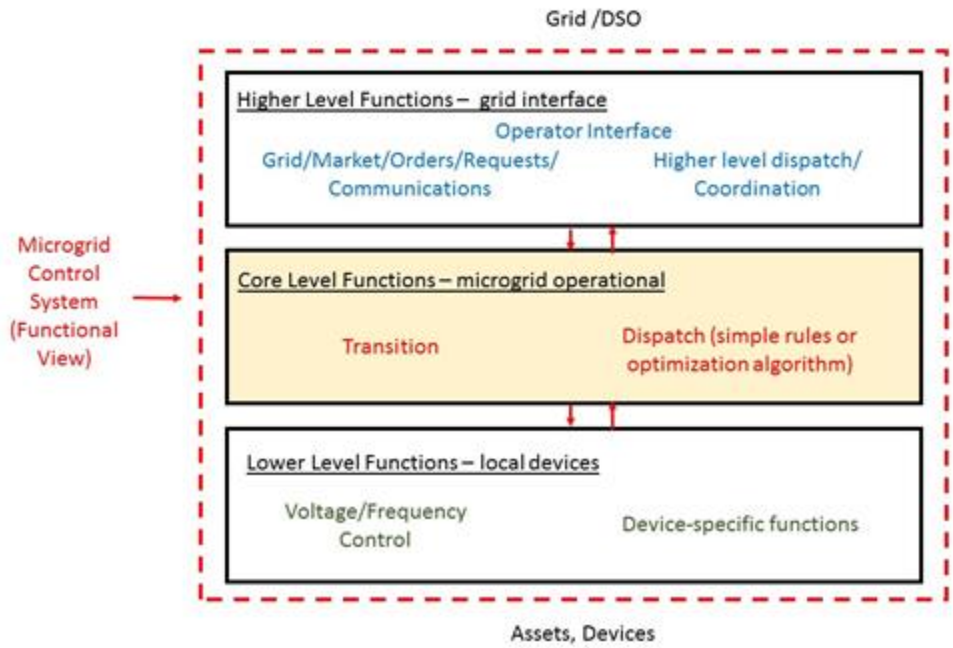
[1] Razeghi, G, Gu F, Neal R, Samuelsen S. A Generic Microgrid Controller: Concept, Testing, and Insights. Applied Energy. 2018; 229:660-71

[2] Razeghi G, Neal R, Samuelsen S. Generic Microgrid Controller Specifications. Technical Report to the US Department of Energy. 2016.
http://www.apep.uci.edu/Research/PDF/Microgrid/Generic_Microgrid_Controller_Specifications_Oct_2016_Razeghi_Neal_Samuelsen_032318.pdf

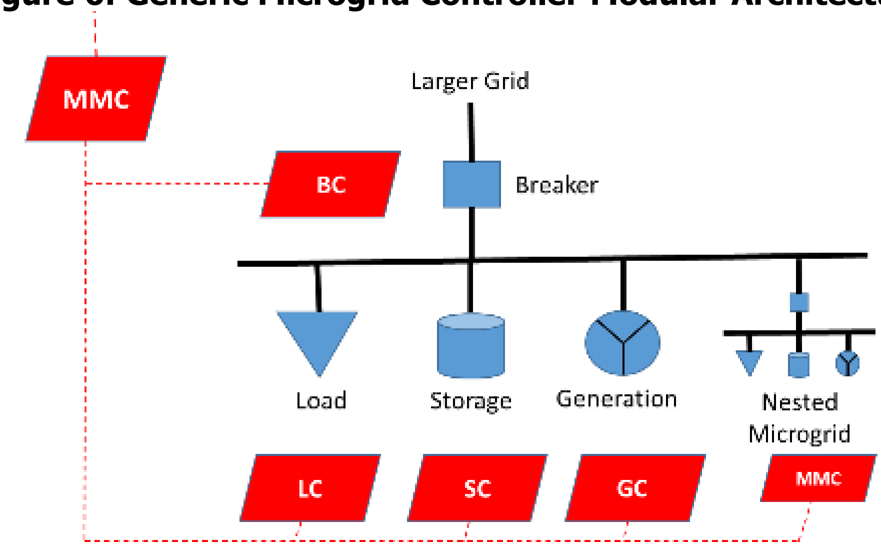
**Figure 5: Generic Microgrid Controller Levels of Control**




Source: UC Irvine

Figure 6 shows the modular architecture of the GMC as well as device level controller (load controller (LC), storage controller (SC), and generation controller (GC)). Core level functions shown in Figure 5 are executed via the Master Microgrid Controller (MMC) which is the brain of the controller and communicates with device level controllers and sends them signals/commands. MMC also communicates with higher level functions and has two major functions: transition, and dispatch as previously discussed.

**Figure 6: Generic Microgrid Controller Modular Architecture**




Source: UC Irvine

# CHAPTER 2:
# Task 2: Base Model Development

In this chapter, the efforts associated with Task 2 are described and the approach and methodology explained. The goal of this task was to model an SCE distribution substation and two circuits by simulating this substation in OPAL-RT. This chapter includes the (1) OPAL-RT software and hardware setup, and (2) description of circuits, models, and methodology.

## OPAL-RT Setup

The automation was simulated digitally on the OPAL-RT platform. OPAL-RT is composed of both software, RT-LAB, and hardware, and is capable of Hardware-in-the-Loop (HIL) simulation in real time. HIL simulation is a method used for the test or simulation, in real-time, of complex process systems for cost, safety and quality improvement before applying the technology to a real environment. Real-time simulation is important in power grid control. Resiliency, and reliability can be measured according to the actual "wall clock" while the grid is under automatic control, making intelligent decisions on its own. The control system or the embedded system can be connected to the HIL simulator, which can mimic the real utility substation in different scenarios. On the RT-LAB platform, the Simulink model was transformed into a real time application, and the simulation run with the real time target using the cores of the OPAL RT hardware. Then the graphical interface was used to change controls and acquire data. Simulation in this project used the ePHASORSIM's phasor domain solver, performing at a typical time-step of few milliseconds. Voltage and current information is provided, representing the same as a phasor measurement unit (PMU) installed in the power grid. This unique electromechanical real-time simulation system enables precise simulation of large-scale networks within a real-time and faster performance.

As a part of Task 2, APEP acquired the OPAL-RT system shown in Figure 7 and Figure 8.

Figure 7: OPAL-RT


Source: UC Irvine

Figure 8: OPAL-RT setup

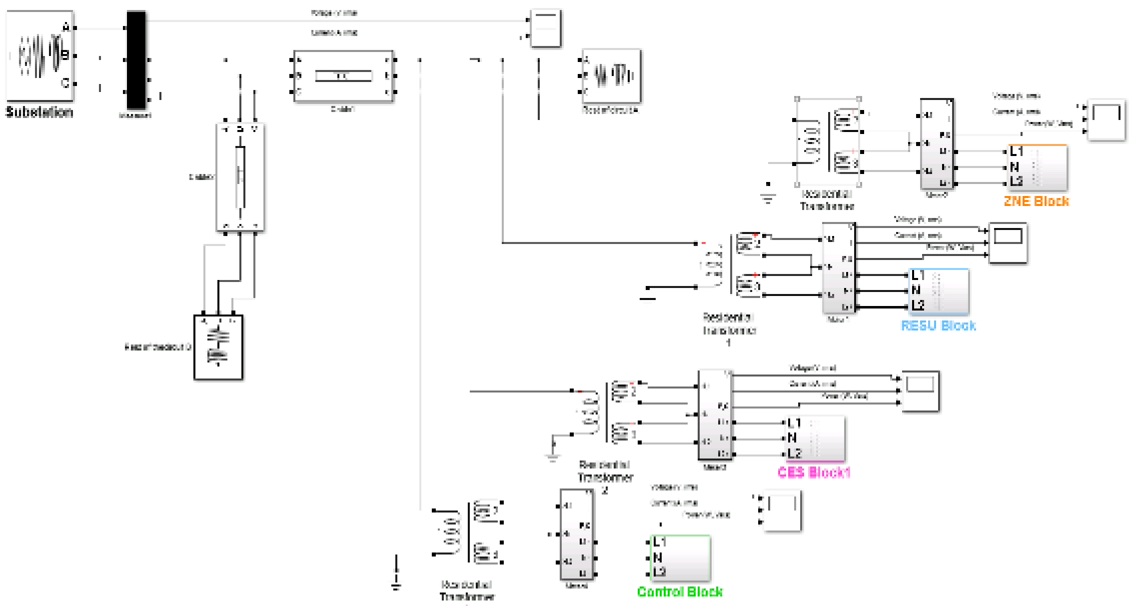
Source: UC Irvine

## System Model and Load Flow

As previously mentioned, two 12 kV circuits (Circuit A and B) were modeled. The ISGD project homes mentioned in the previous chapter constitute a small portion of Circuit A.

As the size of electromagnetic transient (EMT) models of distribution network models that can be simulated in real-time is limited, and the fast transients at frequencies in the kHz captured by these models are not required for the slower time-scale control used for grid integration of distributed energy resources, transient stability (phasor) models were adopted to validate GMC functionality on large-scale distribution circuits with more than 1,000 nodes. The developed model represents the two 12kV circuits fed from an SCE distribution substation as shown in Figure 9. The circuits are constructed underground. The one-line circuit drawings, provided by SCE, were used to develop models on MATLAB Simulink. The ISGD project blocks were modeled in detail in the circuit. The Zero Net Energy (ZNE) block was modeled as a smart-home to achieve zero net energy with 4kW rooftop solar photovoltaic (PV) panels and 4kW/10kWh battery storage along with electric vehicle charging equipment and other various dispatchable loads (such as HVAC and smart appliances including smart fridge). Also the Residential Energy Storage Unit (RESU) block and the Community Energy Storage (CES) block were modeled with the same equipment but with 4kW/10kWh battery storage in each home for the RESU block and a 25kW/50kWh battery near the distribution transformer for 9 homes of the CES block. The load associated with the ZNE block is adjusted to reflect the energy efficiency measures implemented in these homes.

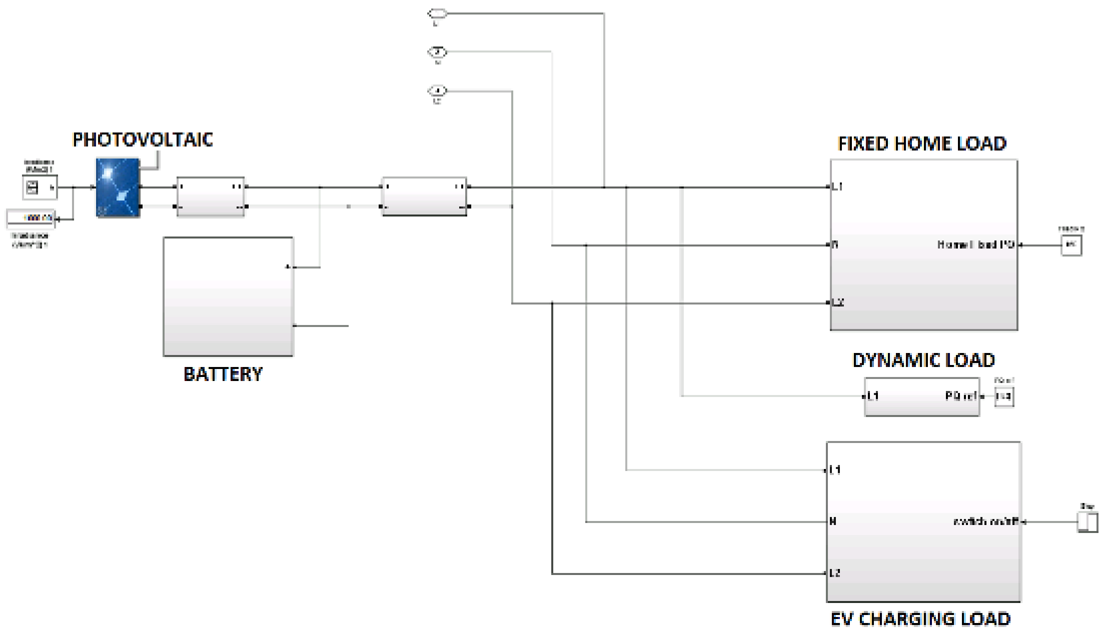
**Figure 9: Circuit Model**




Source: UC Irvine

The rooftop solar PV array model was shared by the OPAL-RT-project partner. This PV model has insolation, temperature, 3-phase grid voltage and reference real and reactive power as inputs, and creates 3-phase current injections as its output. The current injections can either be in the form of sinusoidal waveforms for EMT simulation or as current phasors (magnitude and angle) for TS simulation. The model uses a single ideal diode structure for the DC output of the PV cells, the voltage being a function of insolation and temperature. A perturb-and-observe MPPT (maximum power point tracking) controller was used to maintain PV power output at peak power. The next stage of the model is a boost converter followed by a voltage source converter to create the desired AC output as commanded by the real and reactive power commands. A curtailment function was included to handle situations when the commanded real and reactive power exceeds the power output of the PV cells. Different types of PV brand and model can be selected and set the parallel strings and series connected modules per string for the capacity of the PV. Each PV array was set to deliver a maximum of 3.6 kW at 1000W/m² sun irradiance. The PV array was then connected to a boost converter with the maximum power point tracking (MPPT) controller to track the maximum power point and boost the voltage. Then a DC-AC inverter was connected to switch the DC voltage to the needed AC voltage. This model is included in Figure 10.

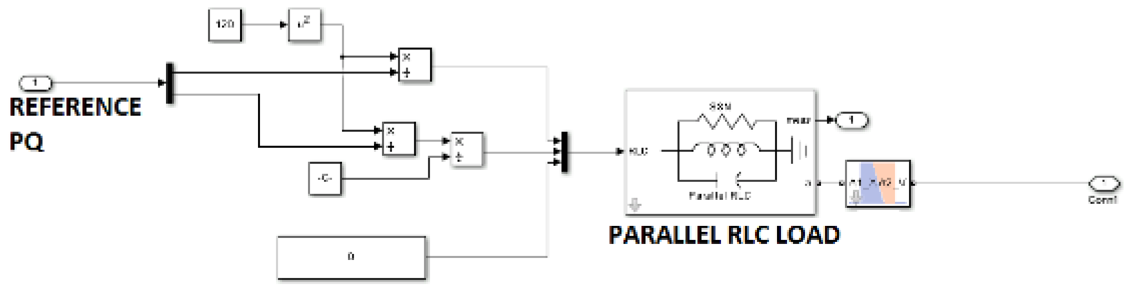
**Figure 10: Home Model with Photovoltaic and Battery**




Source: UC Irvine

The battery was modeled to be controlled with the current, and controlled to operate at different charge and discharge modes by the controller which was developed with the Generic Microgrid Controller specifications in Task 4. For the simulation of the home model, the current from the PV was fed into the battery to charge and the battery discharged when PV generation was zero. Similarly, the battery for the CES block charged from the grid next to the transformer and discharged when the total load on the transformer was larger than 25kVA. All the home models were modeled with dispatchable loads which could be switched on and off or adjusted to a required amount. This was also a control point for the controller. A dynamic load block was modeled as shown in Figure 11 and connected in the home block to enable this feature.

**Figure 11: Dynamic Load Model**




Source: UC Irvine

The control block was modeled as well. This block does not include any distributed energy resources, renewable generation, dispatchable loads, and electric vehicles. A total of 4 blocks and 32 homes are modeled as the ISGD project and the rest of the loads are identified as lumped loads throughout the circuit. In Task 3, various scenarios will be developed and the penetration of renewables and DERs will be increased on these circuits to study their impacts. In addition ZNE homes will be simulated throughout the circuit along with other technologies.

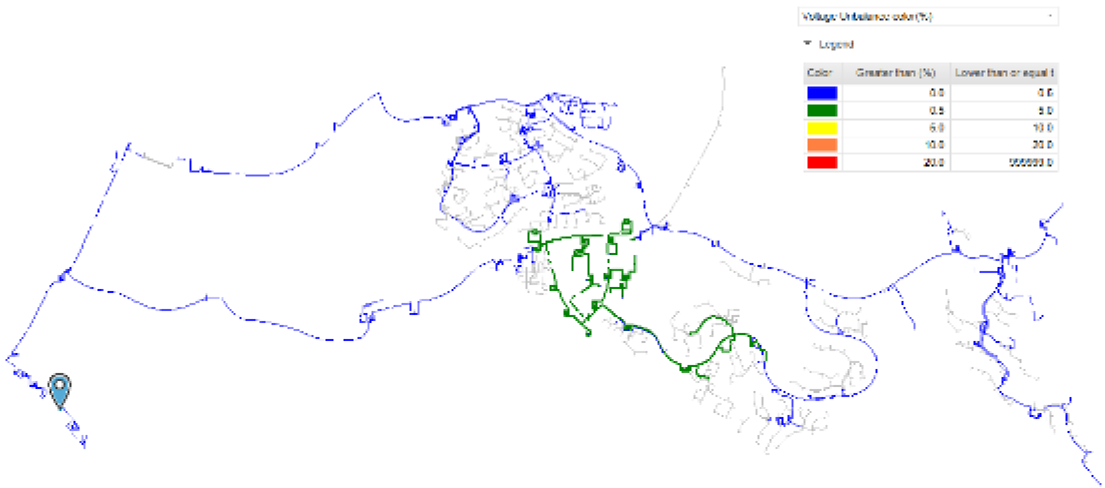
The existing CYME models were imported into the OPAL-RT ePHASORsim environment for real-time simulation. Analysis of the CYME file indicated that specific transformer models are not currently supported in the import functionality of ePHASORsim. These models need to be added to CYME-to-ePHASORsim converter developed by OPAL-RT and work is currently on-going in this regard.

Once the import functionality of the transformer models in the network was addressed, namely the model was configured to allow real-time simulation of the network with controllable loads and distributed energy resources at various points in the network. The model was also set up to communicate with the GMC using standard communication protocols such as IEC 61850 or DNP3.

## Load Flow Analysis

With the as-is circuit model, a power flow study was performed using the CYME software. The voltage drop calculation technique was used which computes the voltages and power flows at every node of the model within 10 or less iterations and the load profiles are preset to values used from SCE. By running the load flow analysis, results for the 2 circuits are shown below. The abnormal over and under voltages were within the +-5% limits (Tables 1 through 3). Figure 12 shows the circuit lines with the voltage unbalance.

**Figure 12: Circuit with Voltage Unbalance**



Source: UC Irvine

**Table 1: Load Flow Results, Total Summary**

| Total Summary | kW | kVar | kVA | PF (%) |
|---|---|---|---|---|
| Sources (swing) | 11886.75 | 3572.75 | 12412.06 | 95.77 |
| Generators | 0.00 | 0.00 | 0.00 | 0.00 |
| Total Generation | 11886.75 | 3572.75 | 12412.06 | 95.77 |
| Load read (non-adjusted) | 11675.99 | 4377.93 | 12469.77 | 93.63 |
| Load used (adjusted) | 11675.89 | 4378.65 | 12469.92 | 93.63 |
| Shunt capacitors (adjusted) | 0.00 | -1128.64 | 1128.64 | 0.00 |
| Shunt reactors (adjusted) | 0.00 | 0.00 | 0.00 | 0.00 |
| Motors | 0.00 | 0.00 | 0.00 | 0.00 |
| Total Loads | 11675.89 | 3250.00 | 12119.77 | 96.34 |
| Line losses | 0.00 | 0.00 | 0.00 | 0.00 |
| Cable losses | 201.56 | 264.86 | 332.83 | 60.56 |
| Transformer load losses | 9.13 | 57.89 | 58.60 | 15.58 |
| Transformer no-load losses | 0.00 | 0.00 | 0.00 | 0.00 |
| Total Losses | 210.69 | 322.75 | 385.43 | 54.66 |

Source: UC Irvine

**Table 2: Load Flow Results, Abnormal Conditions**

| Abnormal Conditions | Phase | Count | Worst Condition | Value |
|---|---|---|---|---|
| Overload | A | 2 | Circuit 12kV | 127.61% |
| | B | 2 | Circuit 12kV | 123.39% |
| | C | 2 | Circuit 12kV | 123.23 |
| 9.13<br>Under-Voltages | A | 0 | 5545961:P5545961-XFO | 99.57 % |
| | B | 0 | 5526185:B5526185-XFO | 99.70 % |
| | C | 0 | 5510839:P5510839-XFO | 100.50 % |
| Over-Voltages | A | 0 | GS1350-3$15373 | 103.92 % |
| | B | 0 | GS1350-3$15373 | 103.92 % |
| | C | 0 | GS1350-3$15373 | 103.92 % |

Source: UC Irvine

**Table 3: Load Flow Results, Annual Cost of System Losses**

| Annual Cost of System Losses | kW | MWh/year | k$/year |
|---|---|---|---|
| Line losses | 0.00 | 0.00 | 0.00 |
| Cable losses | 201.56 | 1765.66 | 176.57 |
| Transformer load losses | 9.13 | 79.96 | 8.00 |
| Transformer no-load losses | 0.00 | 0.00 | 0.00 |
| Total losses | 210.69 | 1845.63 | 184.56 |

Source: UC Irvine

# CHAPTER 3: Task 3: Scenario Development

This chapter outlines the efforts associated with Task 3 of the project entitled Scenario Development. The goal of this task was to develop a set of future viable scenarios to be assessed using the models and the controller based on the GMC specifications.

This chapter provides an overview of the scenarios and tests to be performed. The scenarios included in this project cover:

- The various technologies to be added as DER to the circuits under study
- The various smart grid technologies to further enhance controllability of the assets
- The demand response strategies to further optimize the operations
- The maximum DER/renewable penetration that the circuits can handle
- The impacts of DER on the distribution circuit if the maximum penetration is surpassed
- Viable future scenarios to be further assessed using modeling

## Methodology

Scenarios identified in this chapter were executed in accordance with detailed test procedures. Each procedure will:

- Define the purpose of the test
- Identify task objective satisfied by the test
- Describe system test conditions including initial conditions
- Identify parameters to be monitored
- Describe steps of the test
- Identify expected results
- Record actual results
- Record any deviations from test steps
- Perform required post-processing (e.g. emissions and efficiency calculations)

The template used for each category of scenarios and tests is shown in Template A-1 in Appendix A.[3] This procedure and methodology has been previously used by APEP in the. DOE GMC project which resulted in successful testing and development of the GMC.

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[3] GMC Test Plan, Advanced Power and Energy Program, Report to US. DOE, April 2016

As previously mentioned, the GMC has two major functions (transition and dispatch) as shown in Figure 5.[4] The majority of the scenarios assessed in this project (Task 4) focused on the dispatch function in which resources were dispatched in the most economic manner (economic optimization).

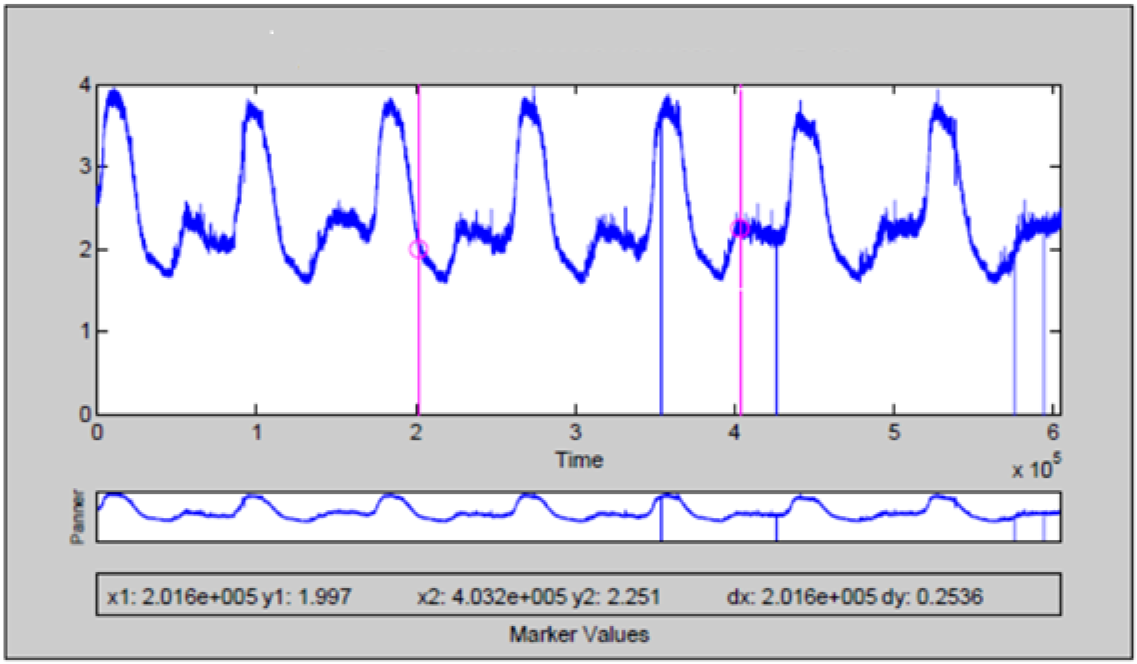
Scenarios were divided in four main groups: high renewable penetration, energy storage, demand response, and circuit-independent. In each group, a variable (e.g. renewable penetration) was changed in the circuit and the simulations were done. The results of the simulation include the load flow in the circuits, cost of generation, and the operation of DERs. Emissions and efficiency were calculated after the simulations. Cases were repeated for different initial and operating conditions to cover different situation (such as winter vs summer and cloudy vs sunny days).

For the DERs, solar PV and battery energy storage were determined to be the most suitable options for the circuits under study. Conventional generators were avoided in order to reduce the environmental impacts. In the demand response scenarios, it was assumed that homes are equipped with smart appliances and energy management systems which can respond to demand response requests. Plug-in electric vehicles were also used in these scenarios as controllable load thus the charger should be able to communicate with the controller.

For the base case, it was assumed that the two circuits have a PV penetration equal to that of the ISGD blocks. The load associated with one of the circuits is shown in Figure 13 for the week of 11/10-11/16 2014. Note that the horizontal axis shows the sample number and not time. These data are recorded at 30 samples per second rate using synchrophasors located at the substation. In the base case, it was further assumed that the electricity demand is rigid and not controllable.

[4] Generic Microgrid Controller Specification, Advanced Power and Energy Program, Report to US DOE, October 2016

**Figure 13: Real Power (MW)- Circuit A**




Source: UC Irvine

## Scenarios

### Scenario 1: High Renewable Penetration

In these scenarios, solar PV penetration in the circuits was increased from the base case to 100%. Based on previous APEP research conducted under a California Solar Initiative (CSI), it was expected that 100% PV penetration is not feasible due to intermittency and instability introduced by PV[5]. Thus, as the PV penetration increases and the simulations repeated, a threshold for the PV penetration on the circuits was established. Studying the scenarios with higher penetration helped identify the issues (system constraints), impacts, and solutions to achieve higher penetrations and increase the threshold. The procedures for these tests are shown in Template A-2 in Appendix A. For the electricity not generated locally and imported from the utility, SCE tariffs and prices were used. For PV, the LCOE was used and calculated from CEC Cost of Generation Model.

Note that after establishing the maximum PV penetration, another feasibility check was conducted to ensure that there is enough roof space or open spaces on the circuits to install this amount of solar PV.

[5] Samuelsen, S.; Brouwer, J. Development and analysis of a progressively smarter distribution system, Final Report, Submitted to CSI RD&D Program Administrator

## Scenario 2: Energy Storage

In these scenarios, battery energy storage was added as another DER to the circuits with maximum PV penetration to assess its impact on the circuits. Furthermore, the PV penetration was increased on these circuits to determine whether or not the addition of energy storage helps to increase the feasible PV penetration in general. These scenarios were divided into the following three groups modeled after ISGD project:

1. RESU (Residential Energy Storage Unit), in which each household has a 4kW/10kWh battery energy storage. In these scenarios, the "mode" (e.g. PV Capture, peak-shaving) of the battery operation was controlled and set by the GMC at the substation. See Template A-3 in Appendix A for the details.
2. CES (Community Energy Storage), in which each block (corresponding to each transformer) is equipped with a 25kW/50kWh energy storage. The operation of these resources was controlled by the GMC. See Template A-4 in Appendix A for the details.
3. Substation (or Circuit) battery: In these cases, a bigger energy storage (2MW/500kWh) was simulated at the substation to support the operation of the two circuits under study. The data collected during ISGD project for such a battery was used. (Note that such a battery existed on one of circuits during ISGD but has since been moved to another location). See Template A-5 in Appendix A. Directed by the results of the simulation, energy storage of different sizes were also simulated.
4. Scenario 3: Demand Response

These scenarios built upon the previous simulations. It was assumed that the system was equipped with energy storage and the corresponding maximum PV penetration for that type of storage determined in Group B simulations. The scenarios were divided in two groups:

1. HVAC and smart appliances: In these scenarios, it was assumed that the homes are equipped with HVAC and smart appliances that can participate in demand response, and with energy management systems (EMS) communicating with the GMC to respond to signals. Details are provided in Template A-6 in Appendix A.
2. Plug-in electric vehicles (PEV): In these scenarios, the homes were equipped with smart appliances and HVAC as the previous group, and a plug-in electric vehicle was allocated to each household. It is further assumed that the chargers were capable of accepting and responding to signals. Details are provided in Template A-7 in Appendix A.

For these scenarios, initially, the current demand response programs and incentives offered by SCE were used.

### Scenario 4: Circuit-Independent

In this scenario, a fuel cell was modeled at the substation to serve as a grid resource in order to fully support the load of the system without having to *import* any electricity from the grid. Thus, all the required generation was produced locally using DERs and with the help of controllable loads. This is similar to operation of a microgrid in islanded mode (dispatch while islanded) and thus the objective was not to meet the load at minimum cost but to meet the load without import. Note that transition from grid connected to islanded and vice versa and the transients associated with transition were not studied in this project. Several options were simulated under this scenario. Details are provided in Template A-8 in Appendix A.

# CHAPTER 4: Task 4: Controller Development

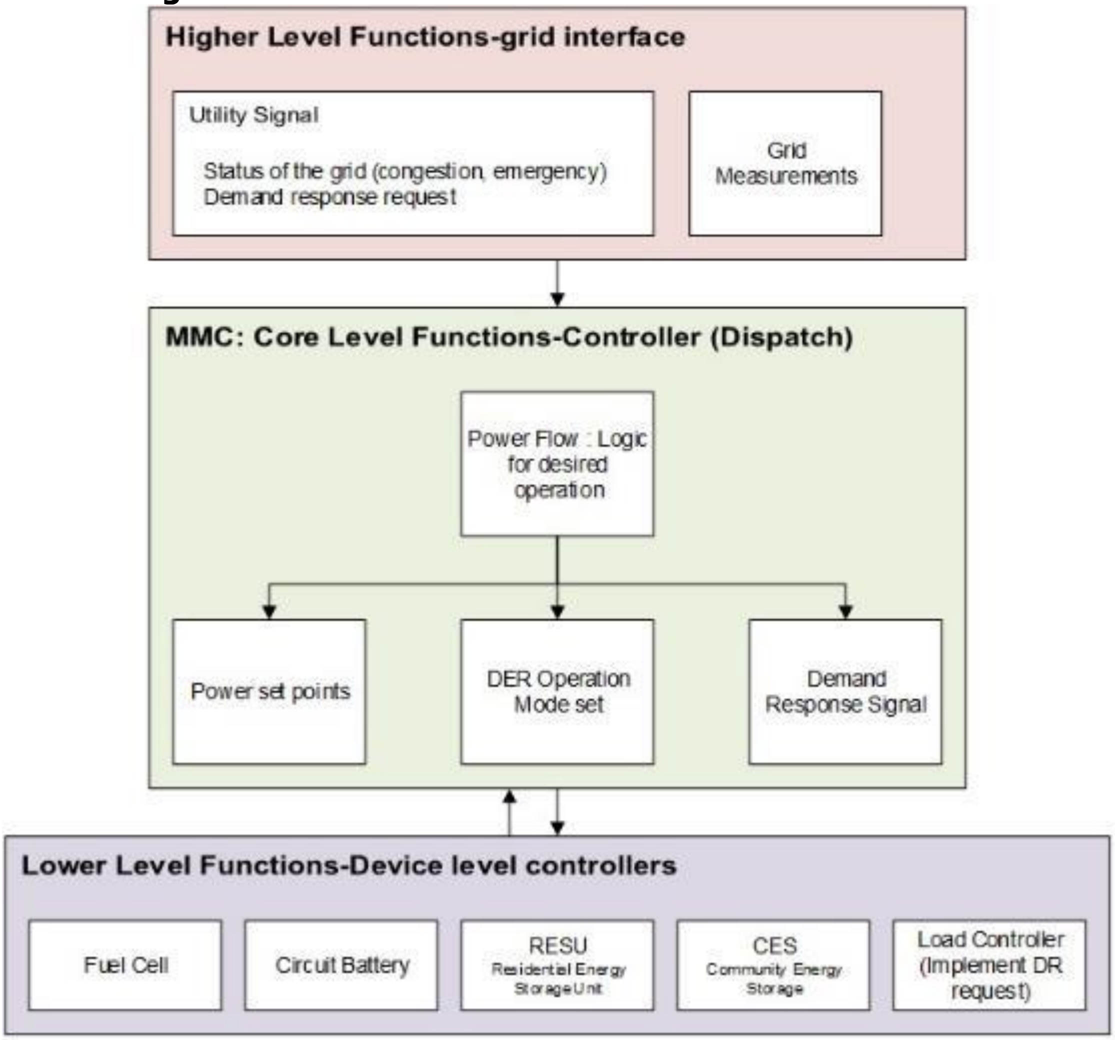
For the purposes of this project, the GMC specifications were used to establish the requirements and functionalities of the controller that was simulated at the substation to enable substation automation and control. A schematic of the controller and three levels of controls are shown in Figure 14 as well as device controllers corresponding to LC, SC, and GC in GMC architecture (Figure 6). Note that core level functions are executed via the MMC. Since transitioning to islanded mode is not included in this project, the breakers are not included in the controls. Utility signals and requests, as well as system status data (including load data) were inputs, and the outputs included signals to the DERs in the two circuits. The DERs on the two circuits included demand response, rooftop photovoltaics and different scales of battery energy storage systems that include combinations of residential energy storage units (RESU), community energy storage (CES), and larger circuit battery energy storage in different scenarios. In one of the scenarios, a fuel cell was simulated at the substation as well.

The batteries had a local (device) control mechanism built in as a model and operated as either (1) residential energy storage units (RESUs) with PV-capture and time-base load shifting modes, or (2)  community energy storage (CES) with permanent load-shifting and load-limiting modes.. These modes are described in details in Section 0 and 0 of this document.

The *mode* of operation was determined by the controller. This was done to avoid sending set-points to individual DERs from the controller, which results in a large number of variables and is impractical for the utility or operator to control thousands of DERs across the grid. The fuel cell operated in either a base-loading or load-following mode determined by the controller, and the demand response signal was sent by the controller to loads' local controller based on the utility request or the need to balance load and generation. Load controllers included the local controller on electric vehicle service equipment (EVSEs) associated with plug-in electric vehicles (PEVs), and energy management system (EMS) of the customer.

the following sections present the local and substation controllers are explained, and their assumptions, logic, strategy, and resulting outcomes.

**Figure 14: Controller Schematic and Levels of Control**




Source: UC Irvine

## Device (Local) Controllers

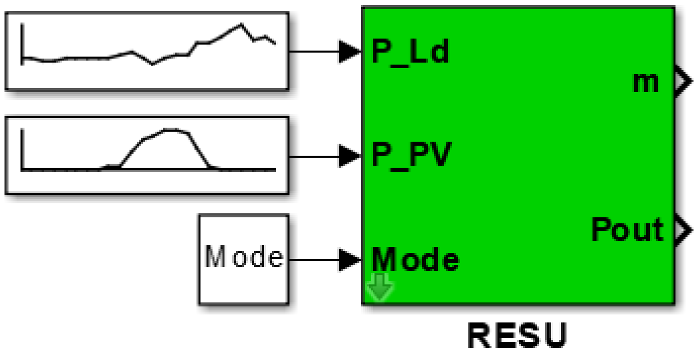
### Residential Energy Storage Unit

#### Model Description

The residential energy storage units (RESUs) were comprised of a PV array and a battery connected to a single inverter. The inputs included the home electricity load, PV array output, and mode of operation. The outputs included inverter power output and a measurement port containing the load power demand, the PV array output power, the battery output power, the inverter output power and the battery state of charge (SOC).

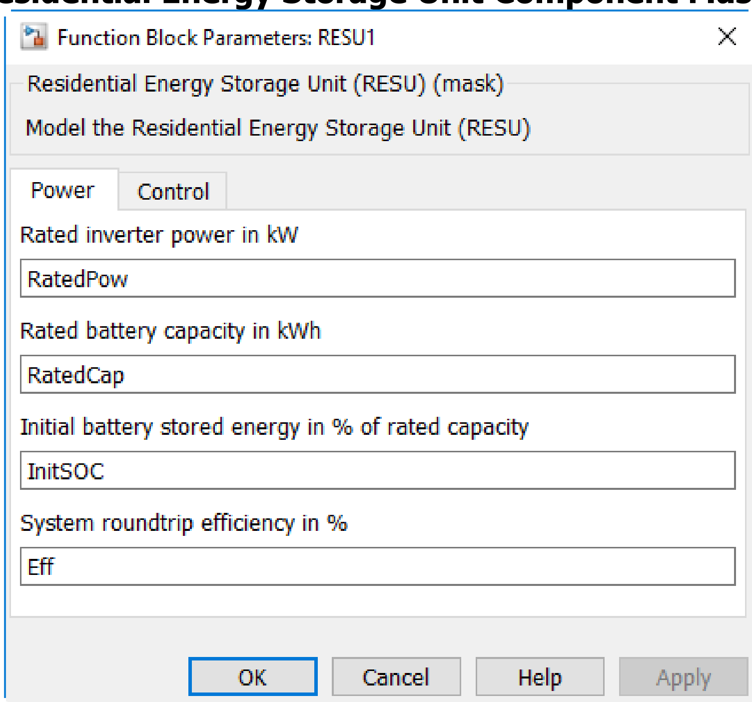
The RESU component and its mask are shown in Figure 15 to Figure 17. The "Power" tab contains the power stage parameters, namely inverter rated power in kW, battery rated capacity in kWh, battery initial SOC in percentage and roundtrip efficiency in percentage. The "Control" tab contains the parameters pertaining to the control stage of the system, namely admissible battery SOC range in percentage, maximum charging power during night time in kW and charging/discharging time interval in hours. The RESU output power is calculated based on the load demand, PV output and battery charge/discharge power, and is further limited by the inverter rated power. The available battery energy is dependent on its SOC.

**Figure 15: Residential Energy Storage Unit Component**



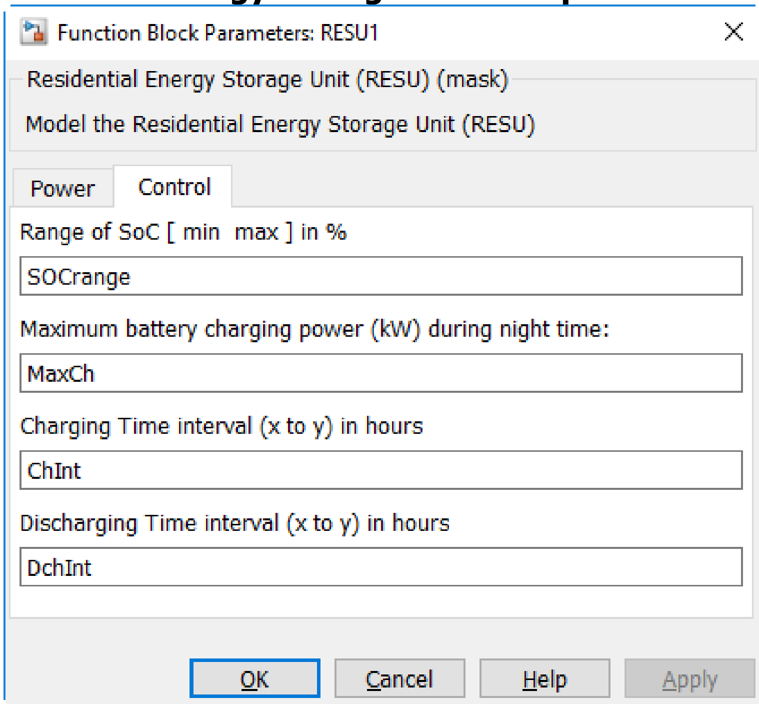

Source: UC Irvine

**Figure 16: Residential Energy Storage Unit Component Mask, Power Tab**




Source: UC Irvine

**Figure 17: Residential Energy Storage Unit Component Mask, Control Tab**

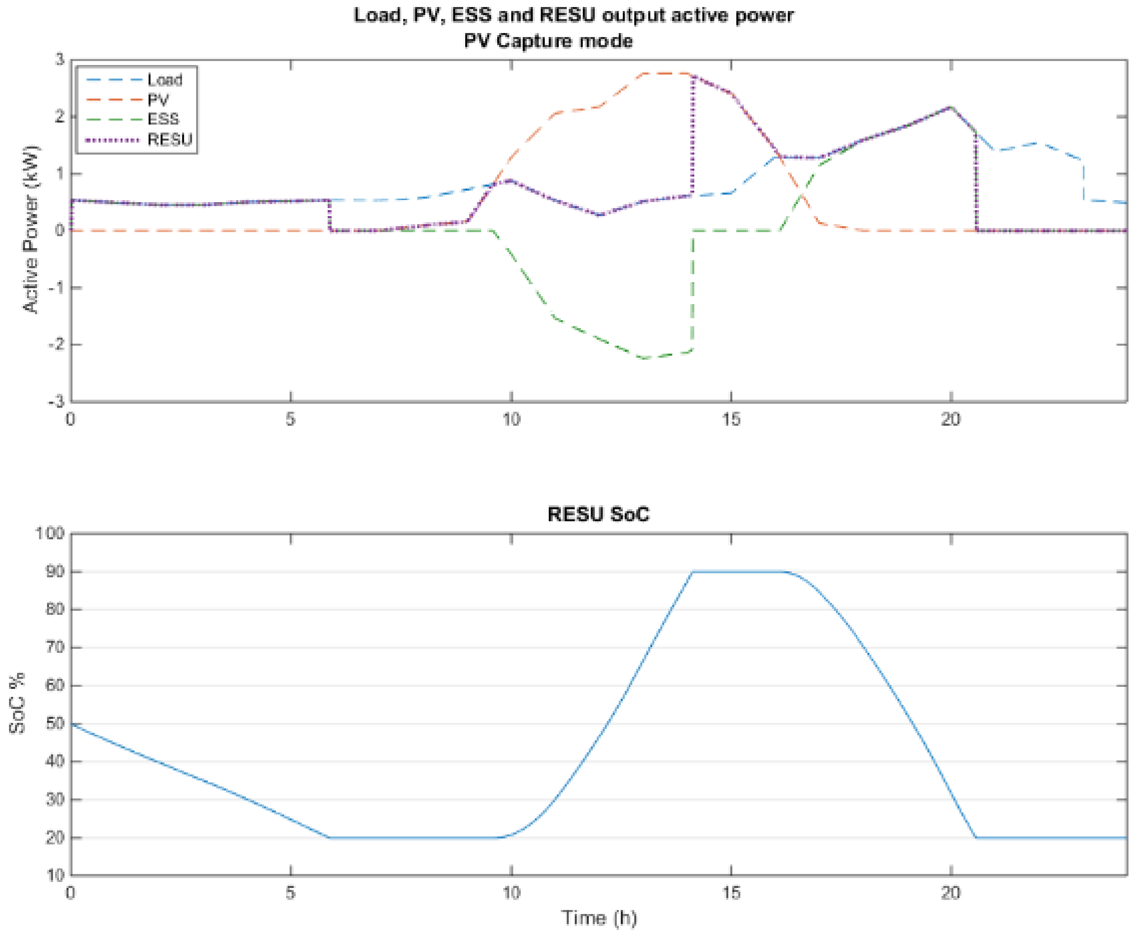



Source: UC Irvine

### Model Control Validation

Two operation modes were modeled for the RESU: PV capture and Time-based load shifting. The control logic for each mode was designed and validated by comparing the simulation results to the data and the field experiment results from the ISGD project. When operating in PV capture mode, the battery output follows its power set-point, which is the difference between the PV output and the load demand, as long as the battery SOC remains within the acceptable predefined range. The battery charges when the PV output is more than the load demand and discharges when it is less. If the battery reaches its maximum SOC and the load demand is met, the surplus PV power is fed back to the grid. Similarly, if it reaches its minimum SOC and the load demand is not met, the grid has to provide the required power. Figure 18 presents the simulation results for a 24 hours period running the RESU in PV capture mode. The load and PV profiles were taken from the ISGD data, the battery initial SOC was set to 50% and the admissible SOC range was set to 20%-90%. Negative power means the battery was charging.

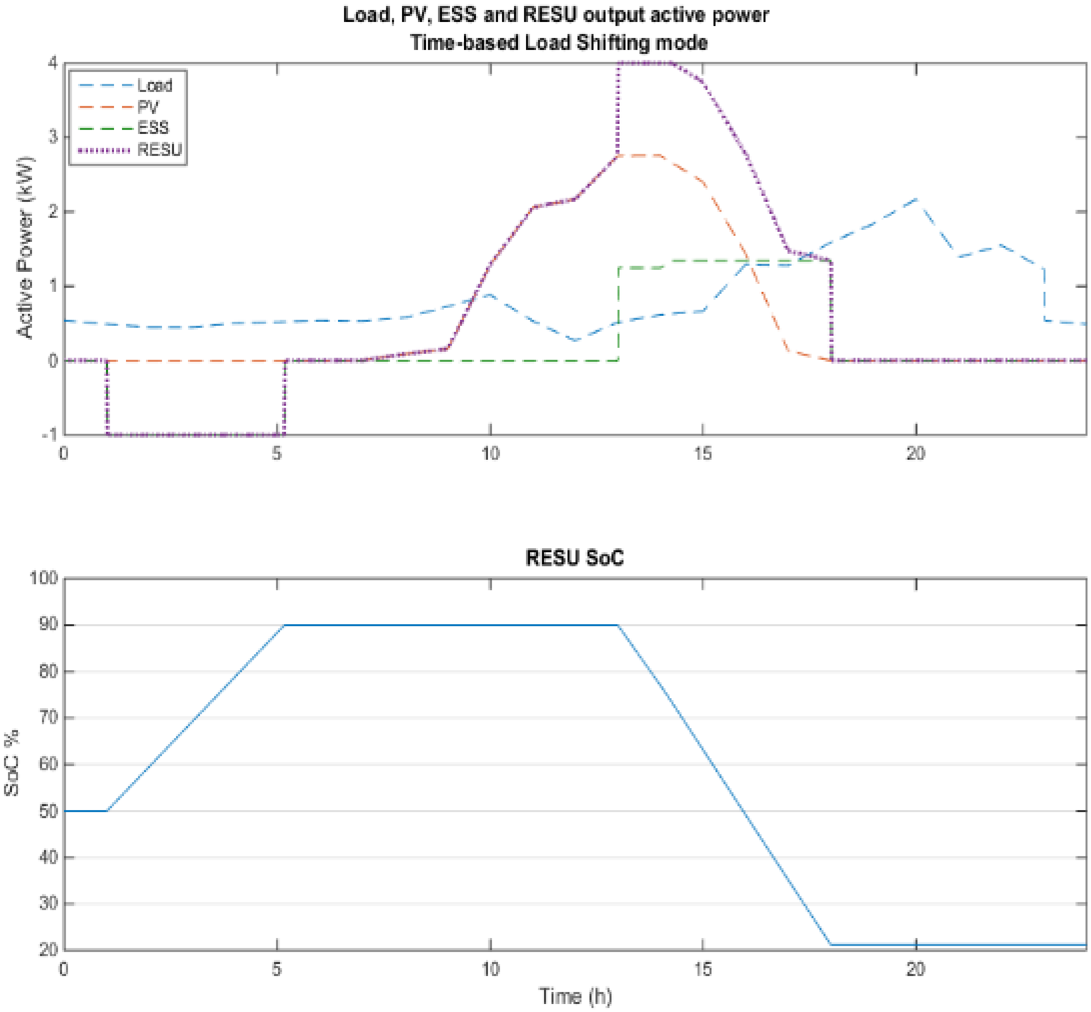
**Figure 18: Residential Energy Storage Unit Simulation Results, Photovoltaic Capture Mode**




Source: UC Irvine

When operating in time-based load shifting mode, the battery charges and discharges during specified time ranges. The charging power set-point was fixed to the specified "Maximum charging power" value, whereas the discharging power was calculated based on the battery SOC and the duration of the specified discharge cycle, so that the battery reaches its minimum SOC at the end of the cycle. The discharging power is also limited by the inverter rating and PV output power. Figure 19 presents the simulation results for a 24 hours period running the RESU in Time-based load shifting mode. The load and PV profiles were taken from the ISGD data, the battery initial SOC was set to 50% and the admissible SOC range was set to 20%-90%. Negative power means the battery was charging.

**Figure 19: Residential Energy Storage Unit Simulation Results, Time-Based Load Shifting Mode**




Source: UC Irvine

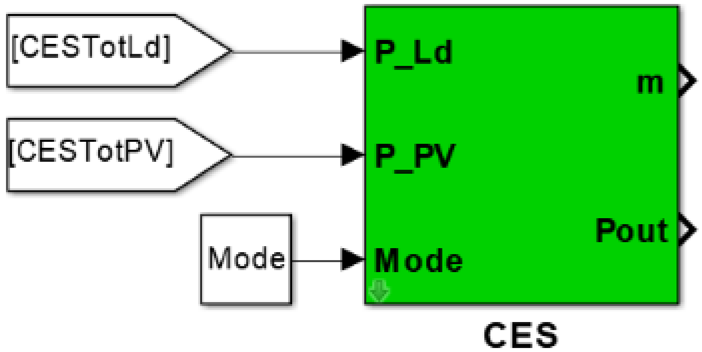
## Community Energy Storage

### Model Description

The community energy storage (CES) units were installed near the distribution transformers and supply all the customers downstream. The inputs were the total load power and PV output power from all the homes downstream as well as the mode of operation. The outputs were the inverter power output and a measurement port containing the total load power demand and total PV output power of the block, the CES output power and the battery SOC.

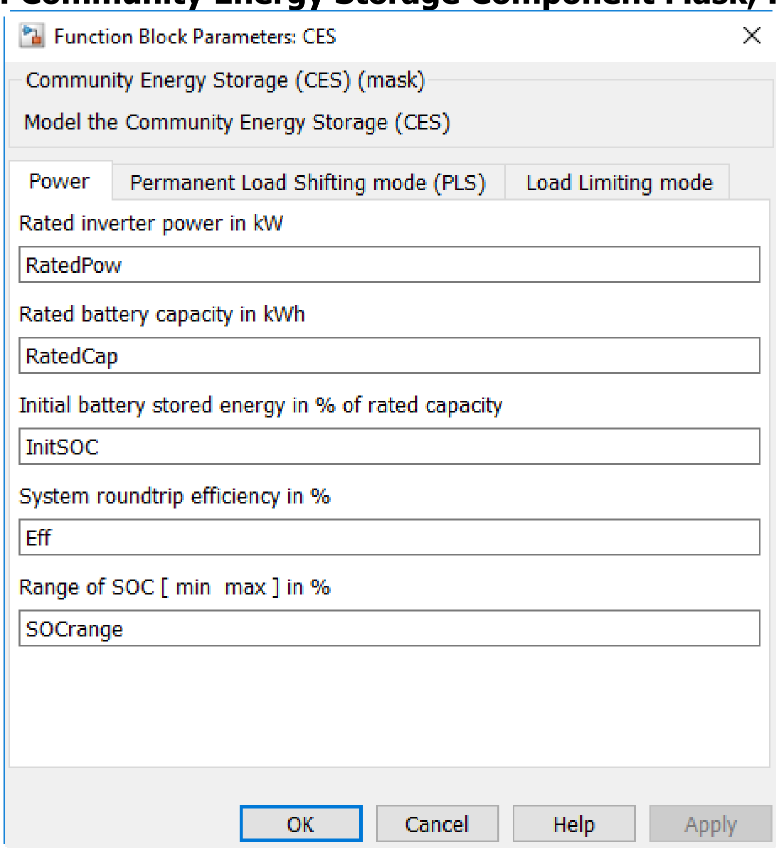
The CES component and its mask are shown in Figure 20 to Figure 23. The "Power" tab contains the power stage parameters, namely inverter rated power in kW, rated capacity of the battery in kWh, battery initial SOC in percentage, roundtrip efficiency in percentage and admissible battery SOC range in percentage. The "Permanent Load

**Figure 20: Community Energy Storage Component**




Source: UC Irvine

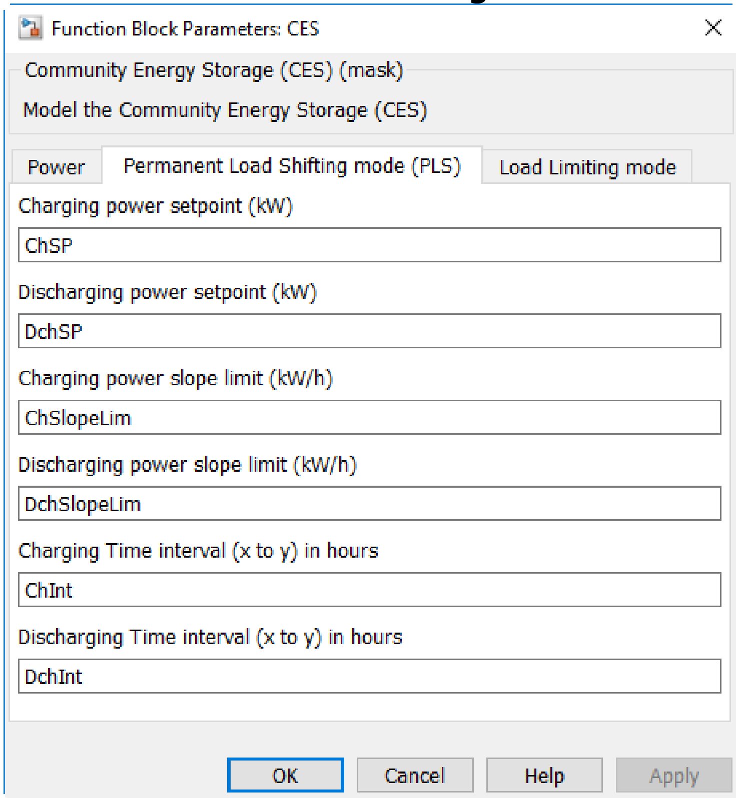
**Figure 21: Community Energy Storage Component Mask, Power Tab**




Source: UC Irvine

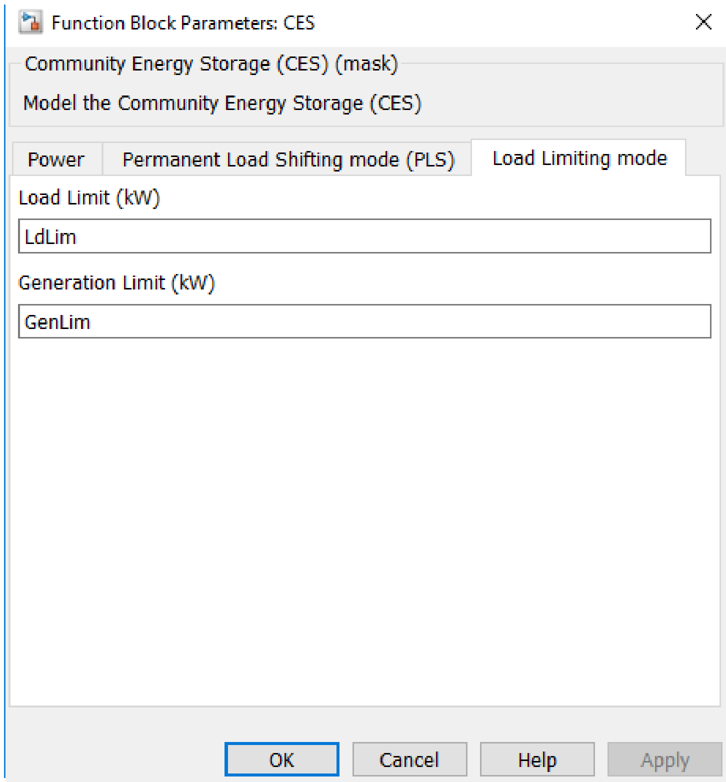
Shifting mode (PLS)" tab contains the parameters pertaining to the CES control stage when operating in PLS mode, namely charging and discharging power set-point in kW, charging and discharging power slope limit in kW/h and time intervals for the charging and discharging cycles. The "Load Limiting mode" tab contains parameters pertaining to the CES control stage when operating in Load Limiting mode, namely the load and generation limits in kW. The CES output power is calculated based on the total residential block load demand and PV output power. It is limited by the CES inverter rated power and also dependent on the battery SOC.

**Figure 22: Community Energy Storage Component Mask, Permanent Load Shifting Mode Tab**




Source: UC Irvine

**Figure 23: Community Energy Storage Component Mask, Load Limiting Mode**

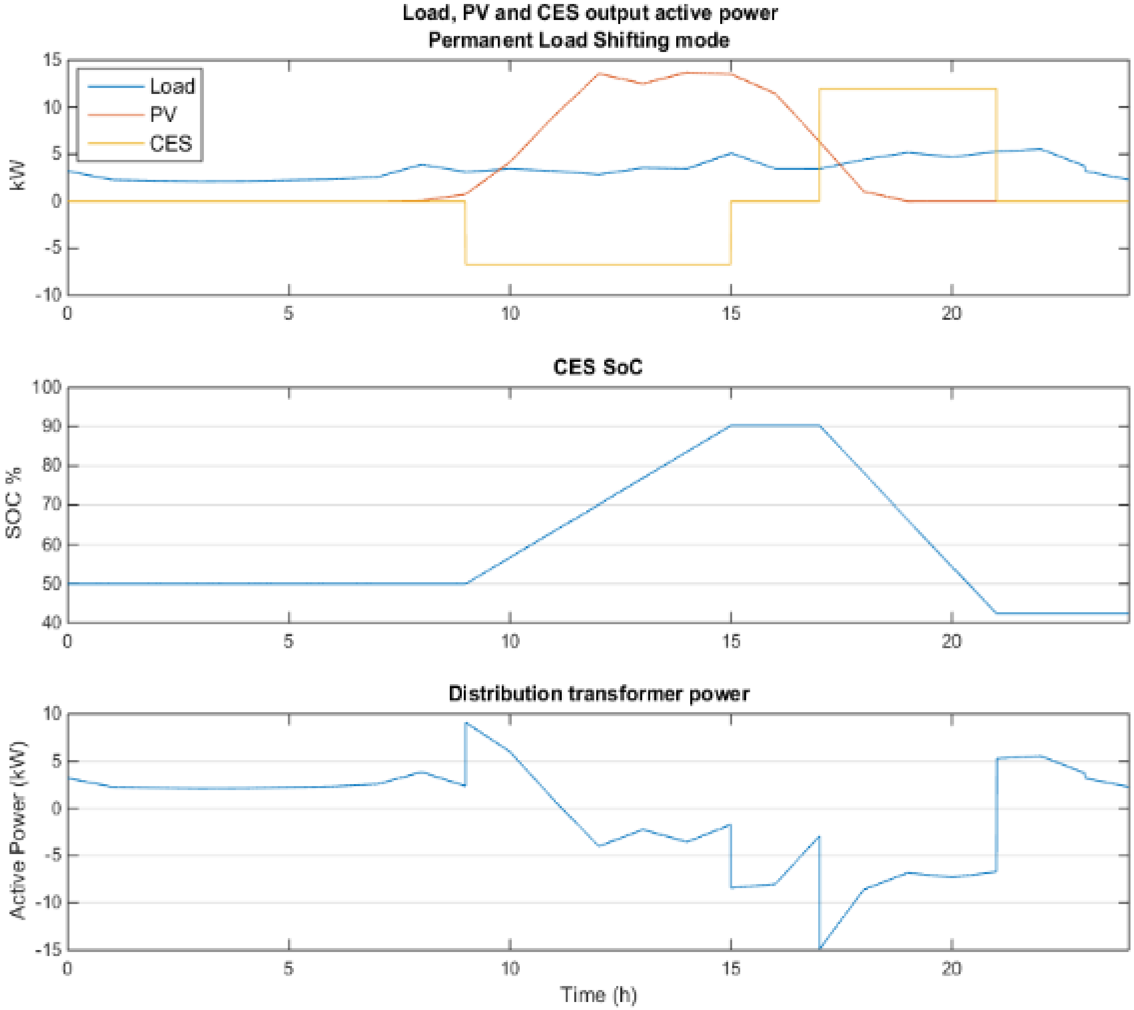



Source: UC Irvine

## Model Control Validation

Two operation modes were modeled for the CES: Permanent Load Shifting (PLS) and Load Limiting. The control logic for each mode was designed and validated by comparing the simulation results to the data collected from the field experiments in the ISGD project. When operating in PLS mode, the battery charges and discharges during specific time windows that are determined by the operator. The charging power set-point was fixed to the specified "Charging power set-point," whereas the discharging power was fixed to the specified "Discharging power set-point". Figure 24 presents the simulation results for a 24 hours period running the CES in Permanent Load Shifting mode. The load and PV profiles were taken from the CES block ISGD data, the battery initial SOC was set to 50% and the admissible SOC range was set to 20%-90%. Negative power means the battery was charging.

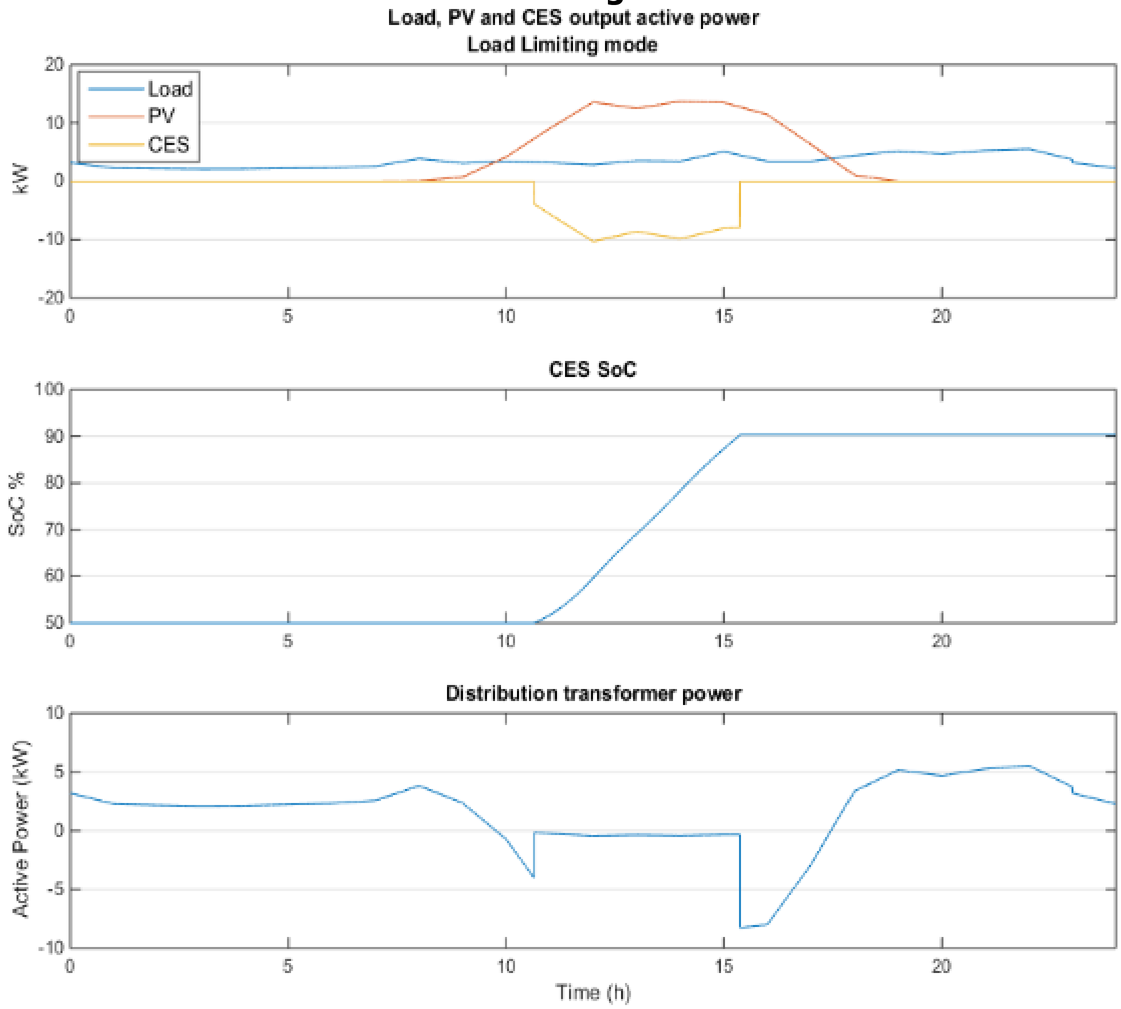
**Figure 24: Community Energy Storage Simulation Results, Permanent Load Shifting Mode**




Source: UC Irvine

When operating in Load Limiting mode, the CES charges and discharges as necessary, were subject to its capacity limits, to limit both imported and exported power at the distribution transformer to the specified set-points. Figure 25 presents the simulation results for a 24 hours period running the CES in Load Limiting mode. The load and PV profiles were taken from the CES block ISGD data, the battery initial SOC was set to 50% and the admissible SOC range is set to 20%-90%. Negative power means the battery was charging.

**Figure 25: Community Energy Storage Simulation Results, Load Limiting Mode**



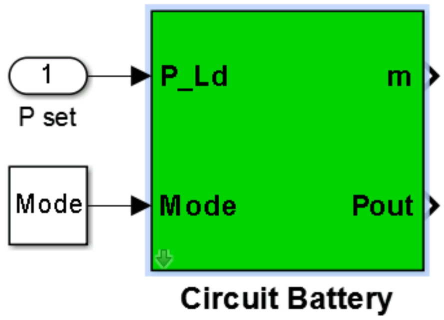

Source: UC Irvine

## Circuit Battery

### Model Description

The circuit battery energy storage model was based on the community energy storage model. Installed near the substation, the battery supplied all the customers downstream. Its inputs were the total load power from all the customers downstream as well as the mode of operation. The outputs included the inverter power output and a measurement port containing the total load power demand, the output power and the battery SOC (see Figure 26).

**Figure 26: Circuit Battery Component**




Source: UC Irvine

The circuit battery energy storage components are the same as the community energy storage with the same function in modes: Permanent Load Shifting (PLS) and Load Limiting.

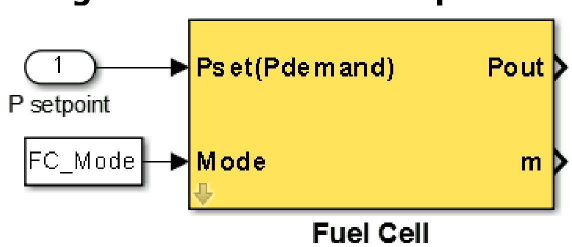
## Fuel Cell

### Model Description

As with the battery, the fuel cell was located near the substation and supplied all the customers downstream. The inputs to the model included the total load power (power set-point) at the substation as well as the mode of operation. Its outputs were the fuel cell power output and a measurement port containing the fuel cell fuel supply amount and the efficiency.

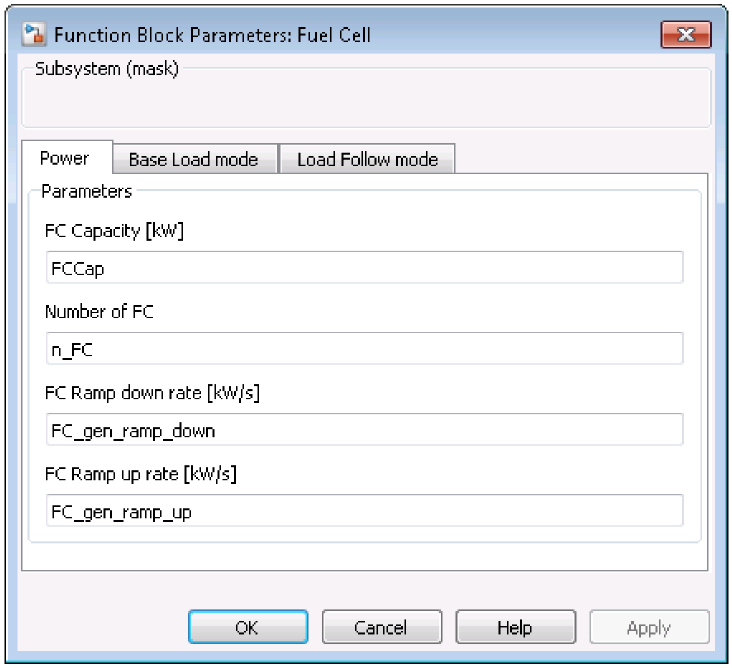
The fuel cell component and its mask are shown in Figure 27 to Figure 30. The "Power" tab contains the capacity and the performance of the fuel cell: rated power in kW, number of fuel cell modules, ramp up and down rate in kW/h. The "Load Follow mode" tab contains the turn down % parameter to set the turndown % of the fuel cell while in operation to follow the demand load/power set-point. The "Base Load mode" tab contains the base load % which sets the percentage use of the fuel cell to deliver a set load/power. This can be set to an output % at the highest efficiency of the fuel cell.

**Figure 27: Fuel Cell Component**



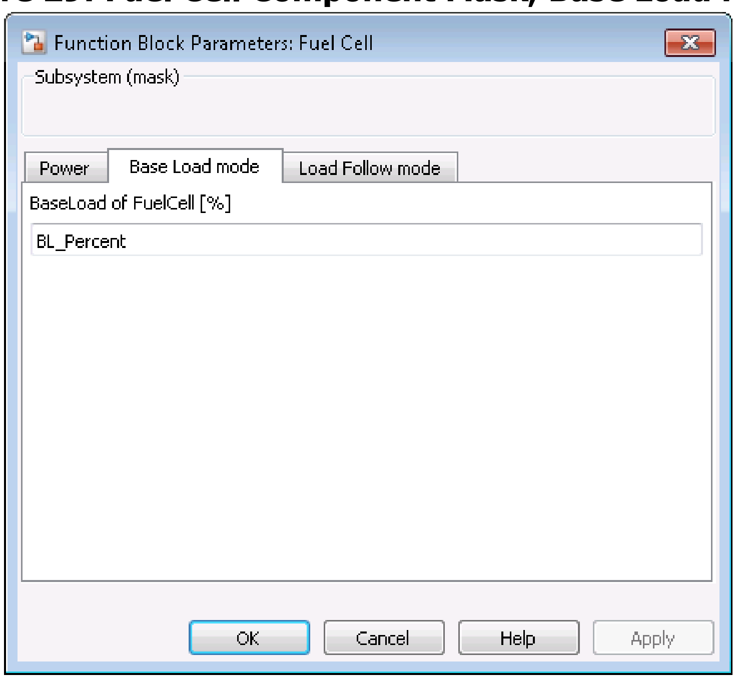

Source: UC Irvine

## Figure 28: Fuel Cell Component Mask, Power Tab



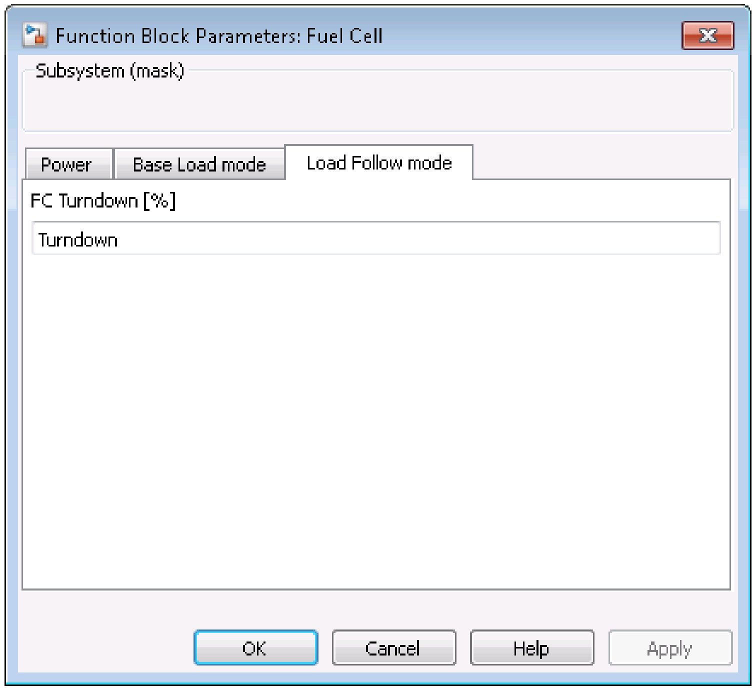

Source: UC Irvine

## Figure 29: Fuel Cell Component Mask, Base Load Mode




Source: UC Irvine

**Figure 30: Fuel Cell Component Mask, Load Limiting Mode**



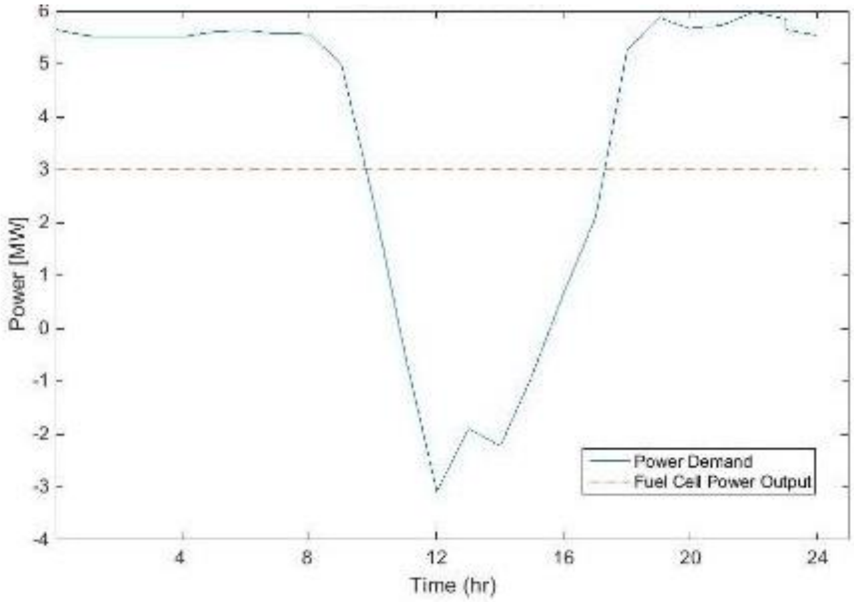

Source: UC Irvine

### Model Control Validation

Two operation modes were modeled for the fuel cell: Base Load and Load Following. When operating in Base Load mode, the fuel cell will supply constant power which is specified with the "base load %" parameter. It will act as a base load supplier at the substation. Figure 31 shows the result of the fuel cell operating at base load mode; the parameters were set to max capacity of 6MW and base load percentage to 50. The fuel cell outputted 3MW constantly throughout a day.

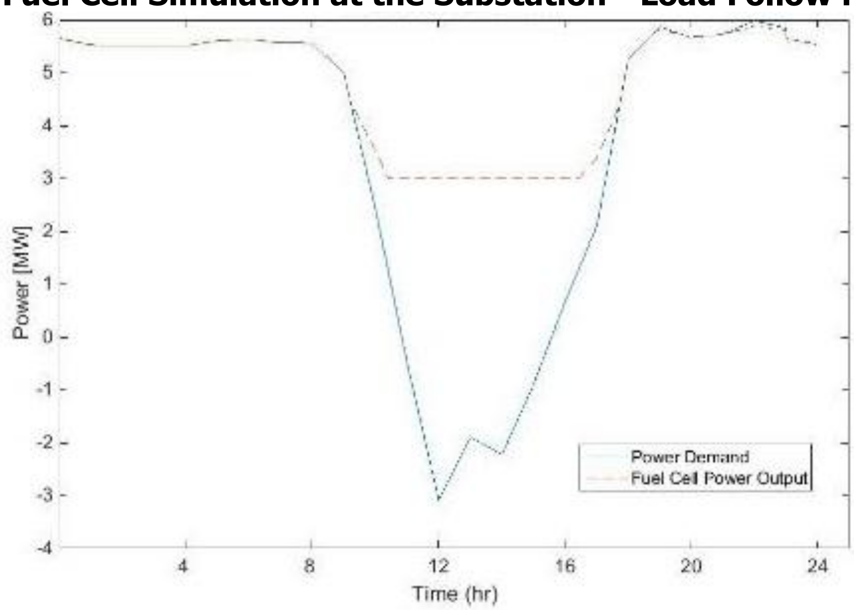
When operating in the load-following mode, the fuel cell outputted power according to the power set point/power demand. The fuel cell followed the load within its power capacity and ramp up and down constraints. Figure 32 shows the result of the load following mode. With the same capacity parameters, 50% turndown set point and 10kW/h and -20kW/h ramp rates, the fuel cell followed the load subject to its operational constraints.

**Figure 31: Fuel Cell Simulation at the Substation – Base Load Mode Result**




Source: UC Irvine

**Figure 32: Fuel Cell Simulation at the Substation - Load Follow Mode Result**



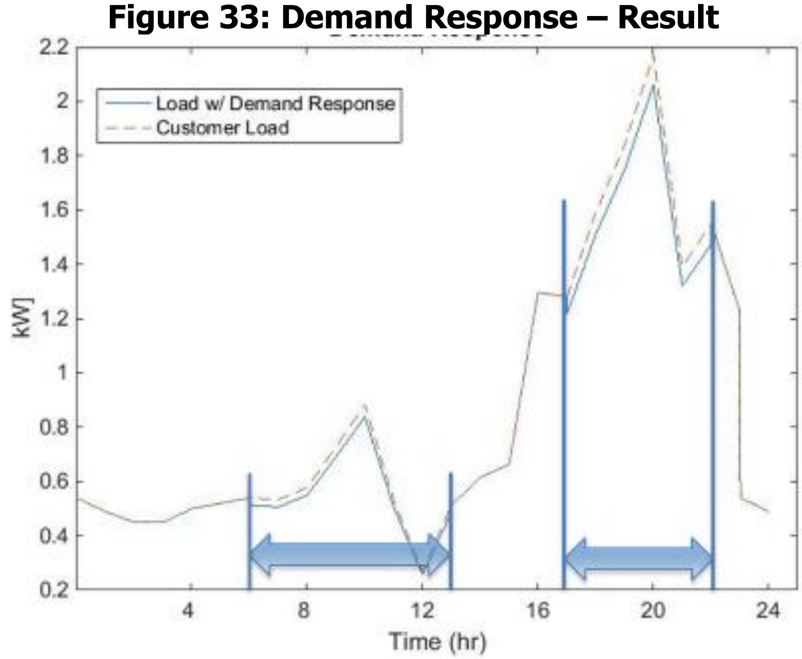

Source: UC Irvine

## Demand Response

Two types of demand response (DR) signals were sent from the controller: 1) HVAC and smart appliance demand response, and 2) Plug-in electric vehicles (PEV). The demand response signal was based on the utility request or it was initiated when physical constraints of the system are violated. The measurements from the two circuits were inputs to the controller and the controller detected when there is abnormal voltage, transmission overflow and transformer overload.

1. HVAC and smart appliances: The demand response signal for home appliances including the HVAC was sent to the load on the circuit. Figure 33 shows the result of a demand response sent to a home during 6am to 1pm and again at 5pm to 10pm. The capacity of load reduction was obtained from the ISGD project's demand response experiments. In practice, this signal will be sent to the energy management system of the residence, and the EMS will make the decision on how to meet the requested DR. EMS and its details are outside the scope of the current project.

**Figure 33: Demand Response – Result**

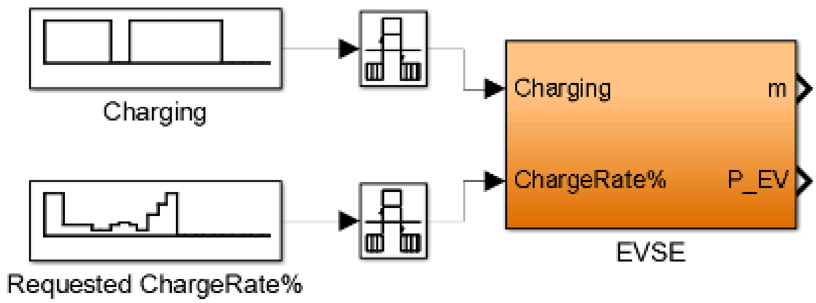



Source: UC Irvine

2. Plug-in electric vehicles (PEV): Demand response was accomplished on the electric vehicle supply equipment (EVSE). With a PEV in each household, a demand response signal was sent from the controller to adjust the charging rate or to turn on and off the EVSE. Figure 34 shows the EVSE charger mask in the model. The designed EVSE logic was based on the ISGD report description and test results and was adapted to fit desired behavior. From midnight to 7am, the EVSE rejected DR events to ensure that the PEV reached full charge in the morning. From 7am to midnight, the EVSE accepted DR events, depicted as "Requested ChargeRate%" in Figure 34, corresponding to changes in the charging rate. Figure 35 presents the EVSE simulation results for one day. The demand response event was selected to test the logic and control. In the result, the EVSE power output corresponding to the DR charge rate % change can be seen. Note that from 7am-10am, the PEV was not connected to the charger (i.e.

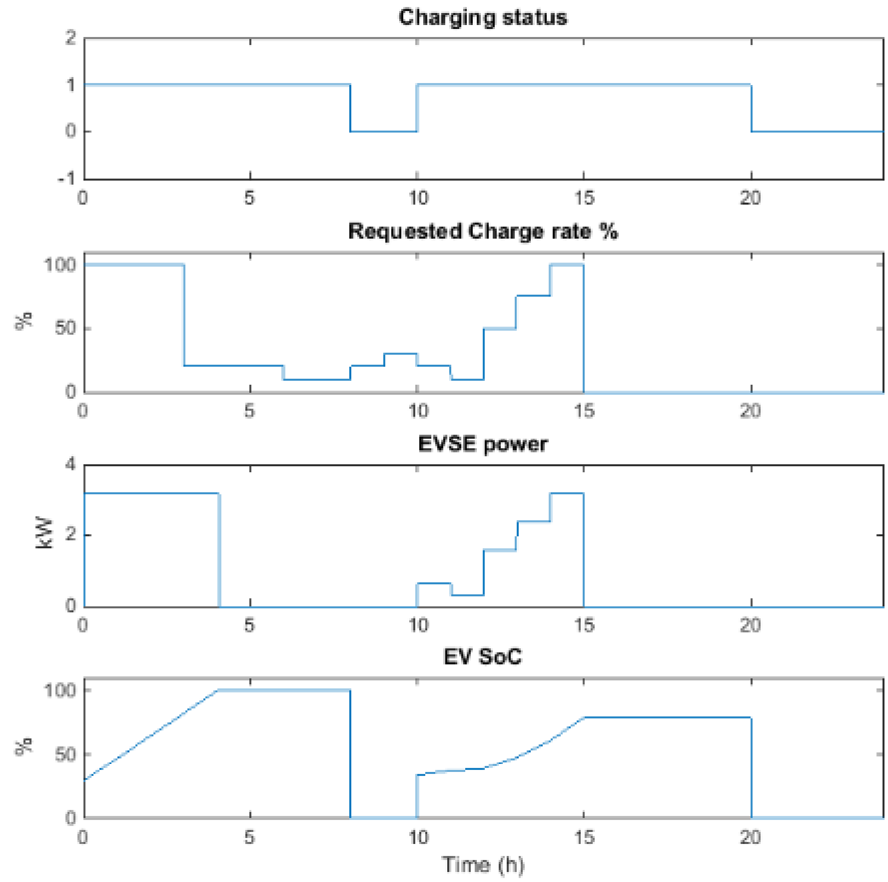
Charging status=0), thus it could not respond to the Requested ChargeRate. Also note, that in these simulations, whenever the PEV was not available or not connected to the charger (i.e. Charging status=0), the SOC was set to 0 due to lack to communication between the EVSE and the vehicle. In these situations the EVSE could not respond to the DR request (Requested ChargeRate%). When the PEV was reconnected to the EVSE, the actual SOC was then communicated to the local controller. For example, at 10am the PEV was connected to the EVSE and the actual SOC was read. The reading was lower than the reading at 7am, indicating that the PEV was driven between these hours

**Figure 34: Electric Vehicle Supply Equipment Mask Model**




Source: UC Irvine

**Figure 35: Electric Vehicle Supply Equipment Demand Response Simulation – Result**



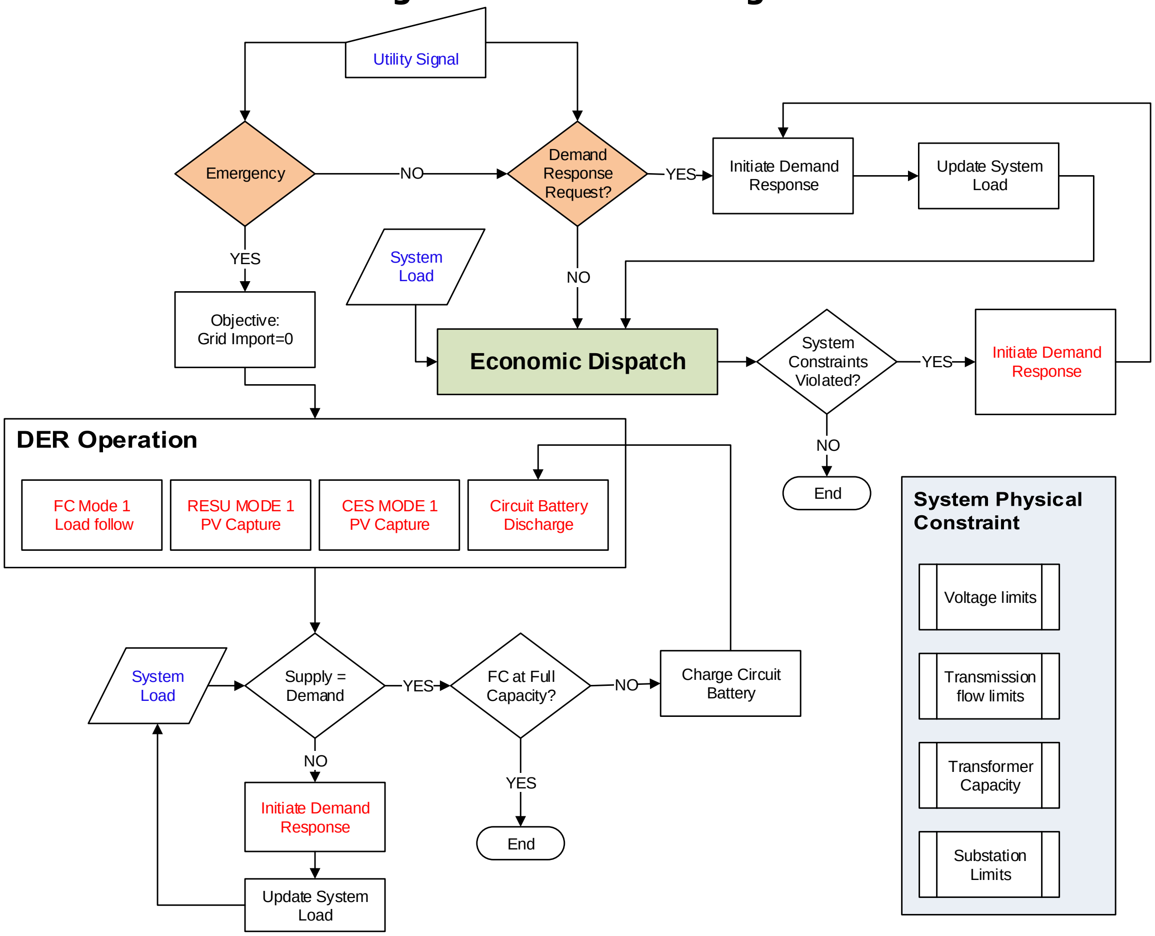

Source: UC Irvine

## Controller Logic

Earlier in the report, the device (local) controllers were described corresponding to lower level functions shown in Figure 14 and previously in Figure 5. In this section, the controller simulated at the substation (substation controller) is described which corresponds to the middle level control shown in Figure 5 and Figure 14 which is the Master Microgrid Controller (MMC). As previously mentioned, the controller included only the dispatch function of the MMC.

As mentioned previously, the controller at the substation sent signals to the device controllers and set the mode of operation. Next, the details of the operation were determined by the device controllers. This was done so that the DERs had a level of autonomy and the customers could determine the details of operation while responding to the requests/demands of the utility or grid operator. The controller logic is shown in Figure 36, and the details of economic dispatch strategy are shown in Figure 37.

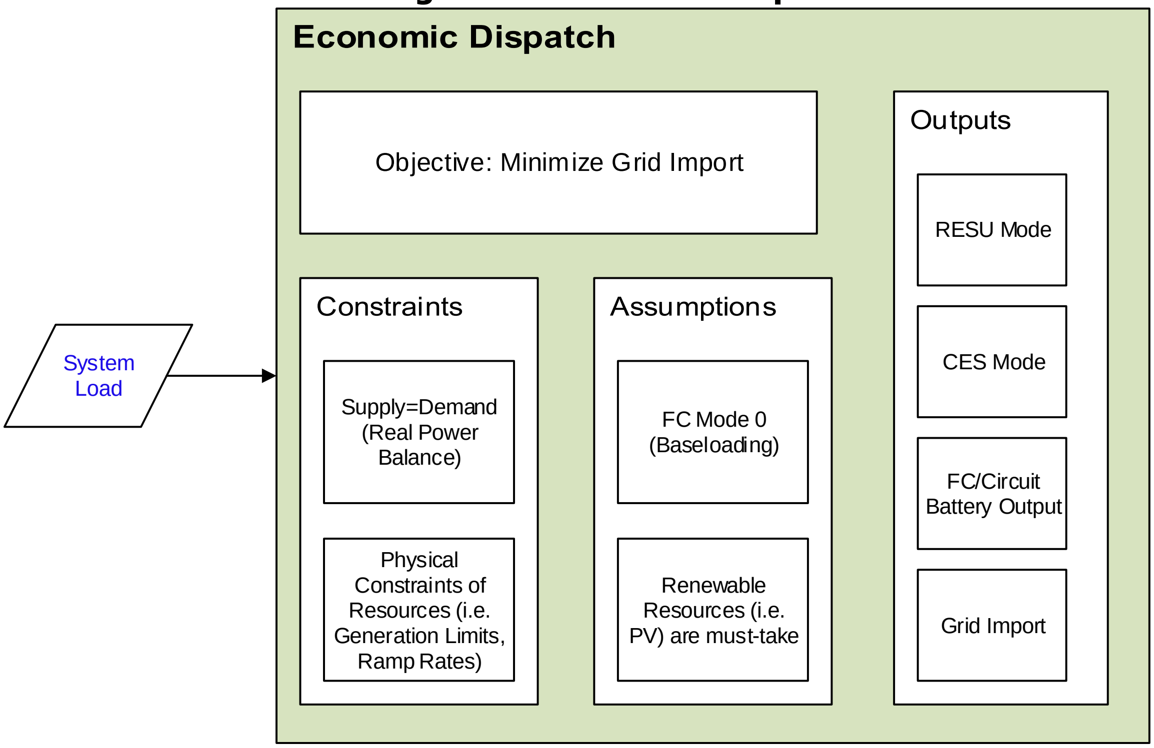
**Figure 36: Controller Logic**




Source: UC Irvine

The major inputs included signals from the utility (or grid operator), system electricity load, and circuit measurement data. The utility signals included a demand response (DR) request, and an emergency signal. The emergency signal refers to situations where the grid was congested, or there was an outage and the controller goes to the "circuit-independent" scenario where all the demand was met by the DERs (including DR). The outputs included signals that the controller sent to the DERs on the circuits: fuel cell, circuit battery, demand response, residential energy storage units and community storage units. In what follows, the controller logic for business as usual operations (emergency signal=0), as well as circuit-independent (emergency signal=1) operations are described.

**Figure 37: Economic Dispatch**




Source: UC Irvine

## Business as Usual

In these situations, the larger grid operation is normal (not an emergency situation) and thus the objective of the dispatch is to meet the demand and requested DR in the most economic way. Depending on whether the utility sends a DR request or not, the two following possibilities are included:

### No Demand Response Request

With no DR request from the utility, the objective is to meet all the electricity load at a minimum cost. To this end, the capital cost of the DERs are not included in this analysis and only the operation costs are included, and the fuel cell is operated in a baseload mode at its maximum efficiency level. These assumptions are made to ensure that the DERs are used to the maximum extend. Including the capital costs (or using LCOE) will result in all the electricity to be supplied by the utility since the technologies dispatched are more expensive than the utility's rate which include a lot of conventional generation. With these assumptions, the cost of the RESU, CES and circuit battery will be the cost of operation (including maintenance) with the addition of fuel cost for the fuel cell. Thus the objective of the optimization becomes to minimize the electricity import from the grid (meet the demand with as much as DER as possible). Furthermore, it is assumed that the mode of operation for a particular class of DERs is the same (i.e. all the RESUs are in mode 1 or all are in mode 0.)

The constraints of the optimization include balance of supply and demand, as well as physical constraints of the DERs such as rated capacity, ramp rates, and etc. The outputs of the optimization will include set-points for the fuel cell, and modes of operation for other DERs. The optimization process including the optimization objective, constraints, assumptions, inputs and outputs are shown in Figure 37.

The objective function is shown in Eq (5.1). In this equation, D(t) is the total load of the circuits seen at the substation at time *t*, *i* is the number of RESUs and *j* is the number of CESs deployed in the circuits, *RESU(i,t)* is the output of the *i*-th RESU at time *t, CES(j,t)* is the output of the *j*-th CES at time *t, CB(t)* is the output of the circuit battery at time *t,* and *FC(t)* is the output of fuel cell at time *t.*

$$Minimize\ Import$$

$$Import(t) = D(t) - \left\{ \sum_{i=1}^{N_{RESU}} [RESU(i,t)] + \sum_{j=1}^{N_{CES}} [CES(j,t)] + FC(t) + CB(T) \right\} \quad (5.1)$$

Eq (5.2)-(5.5) describe the detail of the DERs. Eq(5.2) indicates that the output of the RESU is a function of demand of that particular customer ($D_h(i,t)$), the output of that customers PV ($PV_h(i,t)$), and the mode of the RESUs ($mode_{RESU}(t)$). The details of how RESU is calculated in included in the local (device) controller and was described in details is section 5.1.1.

$$RESU(i,t) = f\big(D_h(i,t), PV_h(i,t), mode_{RESU}(t)\big) \quad (5.2)$$

$$CES(j,t) = g\big(D_a(j,t), PV_a(j,t), mode_{CES}(t)\big) \quad (5.3)$$

Similarly Eq (5.3) shows that the output of the CES is a function of all the demand downstream of that CES ($D_a(j,t)$), the sum of all PV downstream of that CES ($PV_a(j,t)$), and the mode of the CESs ($mode_{CES}(t)$). The details of how CES is calculated in included in the local (device) controller and was described in details is section 5.1.2. As previously mentioned, in Eq(5.2) and Eq (5.3) it is assumed that all the RESUs are in the same mode and all the CESs are in the same mode, as a result $mode_{RESU}$ and $mode_{CES}$ are only functions of time (and not *i*, or *j*).

Eq (5.4) and Eq (5.5) show that the outputs of the circuit battery (*CB*) and fuel cell (*FC*) are a function of the circuit load and their respective modes of operation: $mode_{CB}$ and $mode_{FC}$. The details were previously described in sections 5.1.3 and 5.1.4.

$$CB(t) = k(D(t), mode_{CB}(t)) \quad (5.4)$$

$$FC(t) = l(D(t), mode_{FC}(t)) \quad (5.5)$$

Note that in Eq (5.2)-(5.5), $D(t)$, $D_h(i,t)$, $D_a(j,t)$, $PV_h(i,t)$, and $PV_a(j,t)$ are known (from the data collected from the circuits), and only the mode of operation associated with each class of DER are the variables in this optimization.

The optimization is subject to multiple constraints corresponding to physical constraints of the assets and equipment. The first constraint is the balance of supply and demand as shown in
Eq (5.6).

$$D(t) = S(t) \tag{5.6}$$

Output power of each DER is limited by the maximum and minimum power. Maximum power is usually the rated power of that DER, for energy storage the minimum power is the maximum discharge power. For generating units (such as the fuel cell), the minimum power is determined by the economics. The power limit constraints are shown in Eq (5.7)-(5.10).

$$RESU_{min}(i) \leq RESU(i,t) \leq RESU_{max}(i) \tag{5.7}$$

$$CES_{min}(j) \leq CES(j,t) \leq CES_{max}(j) \tag{5.8}$$

$$CB_{min} \leq CB(t) \leq CB_{max} \tag{5.9}$$

$$FC_{min} \leq FC(t) \leq FC_{max} \tag{5.10}$$

Another constraint included is the ramp rate limits associated with the fuel cell for both ramping up and ramping down. This constraint is shown in Eq (5.11). In this equation, $RL_u$ is the ramping up limit and $RL_d$ is the ramping down limit. Since the optimization is done hourly or every 15 minutes, it is assumed that the battery energy storage units are not constraints by ramp rates with this temporal resolution.

$$RL_d \leq (FC(t) - FC(t-1)) \leq RL_u \tag{5.11}$$

The SOC of battery energy storage units (including RESU, CES, and circuit battery (CB)) are limited by the minimum and maximum allowable SOC. These constraints are shown in
Eq (5.12)-(5.14).

$$SOC_{CB,min}(t) \leq SOC_{CB}(t) \leq SOC_{CB,max}(t) \tag{5.12}$$

$$\begin{aligned} SOC_{RESU,min}(i,t) \leq SOC_{RESU}(i,t) \\ \leq SOC_{RESU,max}(i,t) \end{aligned} \tag{5.13}$$

$$\begin{aligned} SOC_{CES,min}(j,t) \leq SOC_{CES}(j,t) \\ \leq SOC_{CES,max}(j,t) \end{aligned} \tag{5.14}$$

The SOC at time $t$ can be determined by the SOC and the discharge (or charge) power at previous time-step *(t-1)*. These constraints are shown in Eq (5.15)-(5.17). In these equations, *EC* is the energy capacity of the energy storage in kWh.

$$SOC_{CB}(t) = SOC_{CB}(t-1) - \frac{CB(t-1) \times \{t-(t-1)\}}{EC_{CB}} \tag{5.15}$$

$$SOC_{RESU}(i,t) = SOC_{RESU}(i,t-1) - \frac{RESU(i,(t-1)) \times \{t-(t-1)\}}{EC_{RESU}(i)} \tag{5.16}$$

$$SOC_{CES}(j,t) = SOC_{CES}(j,t-1) - \frac{CES(j,(t-1)) \times \{t-(t-1)\}}{EC_{CES}(j)} \tag{5.17}$$

Other physical constraints such as rated power of the inverters, are included in the local (device) controllers and the details are provided in section 5.1.

The problem is linear with integer variables (mode of operation of DERs which can be represented by binary values). This constitutes a Mixed-Integer Linear Programming (MILP) problem. This MILP optimization problem is solved using MATLAB Optimization Toolbox (intlinprog specifically), as well as CPLEX.

After the optimization, the results are checked against system constraints (such as voltage limits, and transformer capacity). If any of the system constraints are violated, a demand response sequence will be initiated to meet the demand without violating any system constraints. Note that this is included as a contingency, and the system (and DERs added to the system) are designed in a manner so that the system constraints are not violated even in a worst case scenario.

#### Demand Response Request from Utility

In this situation, a DR signal is sent to the controller from the utility, and the controller initiates a DR response by sending signals to the DR devices as discussed in Section 2.5, the new system load is calculated and will be sent as an input to the economic dispatch and the dispatch will be done the same as explained in the previous section (but with the updated system load).

### Circuit-Independent

In this situation, the utility sends an emergency signal which can be due to congestion, lack of generation resources, or an outage. The objective here is to prevent any import from the utility, and serve the load only with DERs (which can result in dropping loads through DR). The RESU, and CES will be in PV capture mode, the fuel cell in load-following mode and the circuit battery will discharge if necessary. If the demand cannot be met, the required amount of load to be shed will be calculated and a DR sequence will be initiated to balance supply and demand. If the load is met without any DR event and the fuel cell is not at full capacity, the fuel cell will be used to charge the circuit battery in anticipation of the situation continuing to the next time step.

# CHAPTER 5:
# Simulation Results and Discussion

## Scenario 1

This chapter discusses the scenario to explore the maximum allowable PV on the two circuits. In this scenario, the solar PV penetration in the circuits was increased from base case, the current "as-is" case, to maximum PV penetration under electrical constraints of the circuit and available physical footprint of the circuit area (Figure 38).

**Figure 38: Residential and Commercial Areas in the Two Circuits**

Source: UC Irvine

Instead of using the number of customers connected to each secondary transformer, the ISGD block transformer size and connected number of homes were used as the standard for the deployment of PV since the number of customers does not indicate the number of homes to accurately deploy PV on the rooftop (e.g. one apartment building will have more than 1 costumer). For each size of the secondary transformer, the number of homes and PV connected were established as standards as shown in Table 4. Each home was equipped with a 3.6kW solar PV array.

**Table 4: Standard Number of Homes per Transformer**

| Transformer size [kVA] | Number of Homes connected | PV Capacity for each home [kW] | Total PV Capacity [kW] |
|---|---|---|---|
| 50 | 8 | 3.6 | 28.8 |
| 75 /100 | 15 | 3.6 | 54 |

Source: UC Irvine

For the commercial customers/buildings, the physical footprint of the rooftops was estimated using "Google Earth View", and the average solar panel measurements of 39 x 65 inch per 265 watts were used to determine the capacity that the available footprint can host. Figure 39 shows the available rooftop spaces in one section of circuits.

**Figure 39: Building Rooftop Footprint (One Section)**

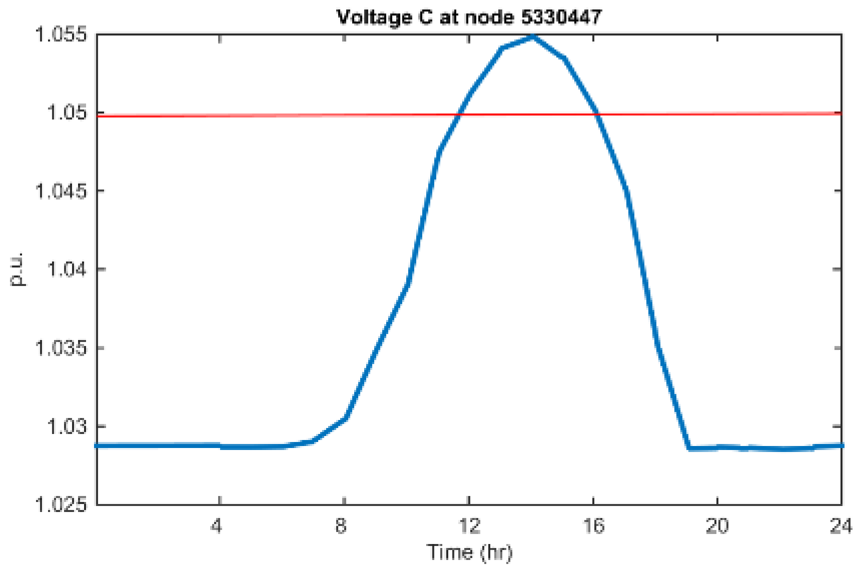

Source: Google Earth

With all the PV deployed on the circuit with the standardized number of homes, the residential sector could host 8.697MW of PV and the commercial sector could host 2.66MW of PV. This resulted in a total of 11.36MW of solar PV on the entire circuit. This was the capacity the circuits can host merely based on the available footprint and rooftop spaces.

The system model previously developed was used to run simulations to determine if any electrical constraints were violated with the deployment of maximum PV established previously solely based on footprint. The simulation was conducted as a worst case scenario where the PV production is at its highest and the load profile at its lowest. This situation led to high gradients in the net load (similar to the famous duck curve) and resulted in abnormal voltage on 13 phase C node points in the system. Figure 40 is a plot of the voltage in a 24 hour period. While the voltage contraint is +/- 5% from the nominal voltage, as can be seen in Figure 40, the voltage shot over +5% at peak PV power generation. After such simulations, the PV capacity was adjusted at each of the 13 nodes (identified previously with volatege violations) and reduced by a total of 1.4MW PV capacity to avoid any violations. Figure 41 is a plot of the voltage at the same node as Figure 40. It is shown that no voltage violations occurred with the new PV capacity.

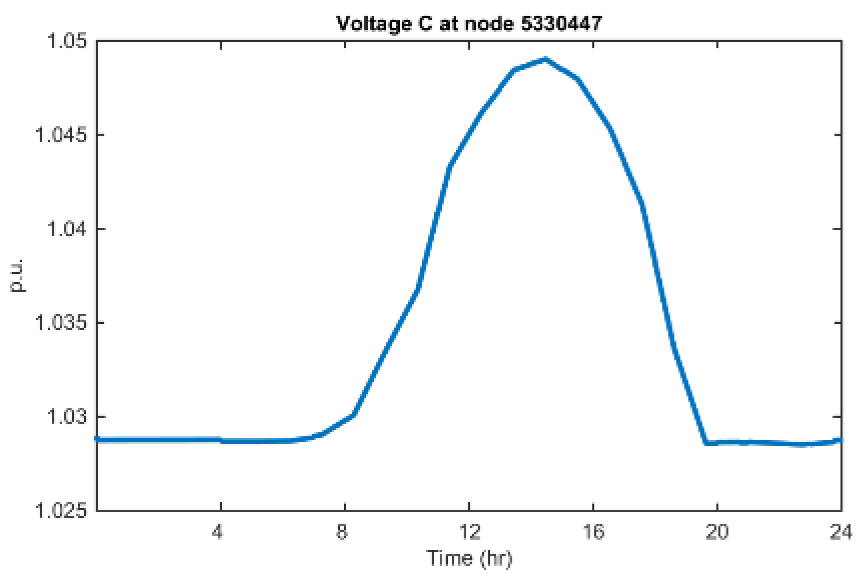
The results show that the maximum PV hosting capacity of the two circuits is 7.235MW on residential housing and 2.66 MW on commercial buildings. Thus a total of 9.89MW of solar PV can be installed on these circuits which leads to great gradients in the power profile (duck curves) but is manageable since the voltage remained within the normal voltage range on all the nodes. This is equivalent to 85.1% PV penetration (based on maximum load on the circuits) on the two circuits given the maximum power at the substation was 11.626MW.

**Figure 40: Overvoltage at a Node with Max Photovoltaic Based on Footprint**




Source: UC Irvine

**Figure 41: Voltage at a Node with a New Adjusted Photovoltaic Penetration**




Source: UC Irvine

## Scenario 2

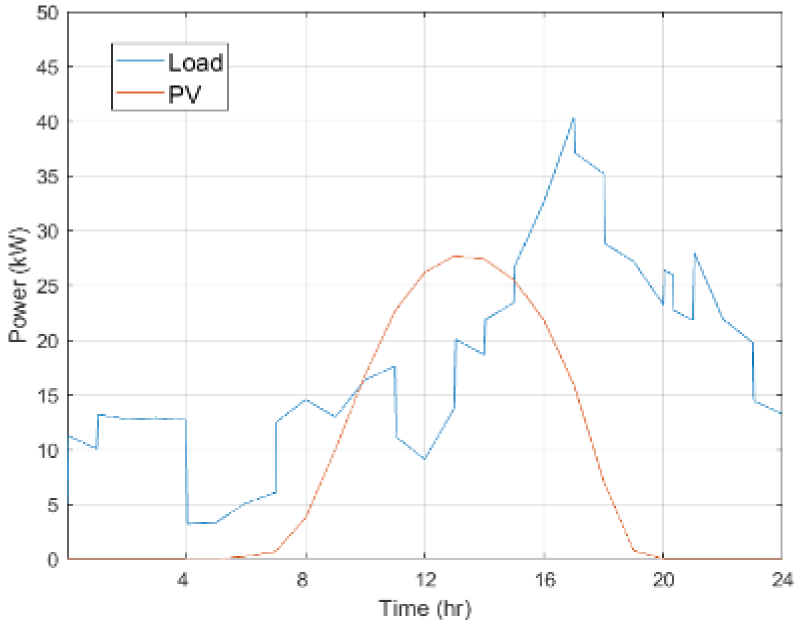
As previously discussed, battery energy storage was added as another DER to the circuits having maximum PV penetration previously determined in order to assess the impact of energy storage in scenarios with high PV penetration. The PV penetration is increased to determine whether addition of energy storage helps increase the feasible PV penetration on these circuits and ultimately the distribution system. The PV capacity increased from 3.6 kW determined in the previous scenario without energy storage to a maximum of 7kW per home which is consistent with data collected in California. Although the U.S. average residential PV has been reported as 5.5kW[6] in the state of California 858 MW of residential solar PV was added in 2017 with an average size of 7 kW per residence[7].

This scenario was divided into three groups, inspired by the ISGD project: 1) Residential Energy Storage Unit (RESU), 2) Community Energy Storage (CES) and 3) Circuit Battery. In this project, the data collected from the ISGD Project were utilized. The load and PV profiles were extracted from the data set associated with a high load and high PV day. May 15$^{th}$, 2014 data of the ZNE block (9 homes), shown in Figure 42 were then chosen for the simulations. The load in Figure 42 also includes the EV load. The EV charge times were included according to the charge pattern determined from the ISGD project. Out of the 9 homes in one block on average, 2 homes charge their EVs in the morning, 1 home in the midday, 4 homes in the afternoon/evening and 2 homes at midnight as shown in Figure 43.

[6] "Solar Photovoltaic Technology," Solar Energy Industries Association. [Online]. Available: https://www.seia.org/research-resources/solar-photovoltaic-technology.

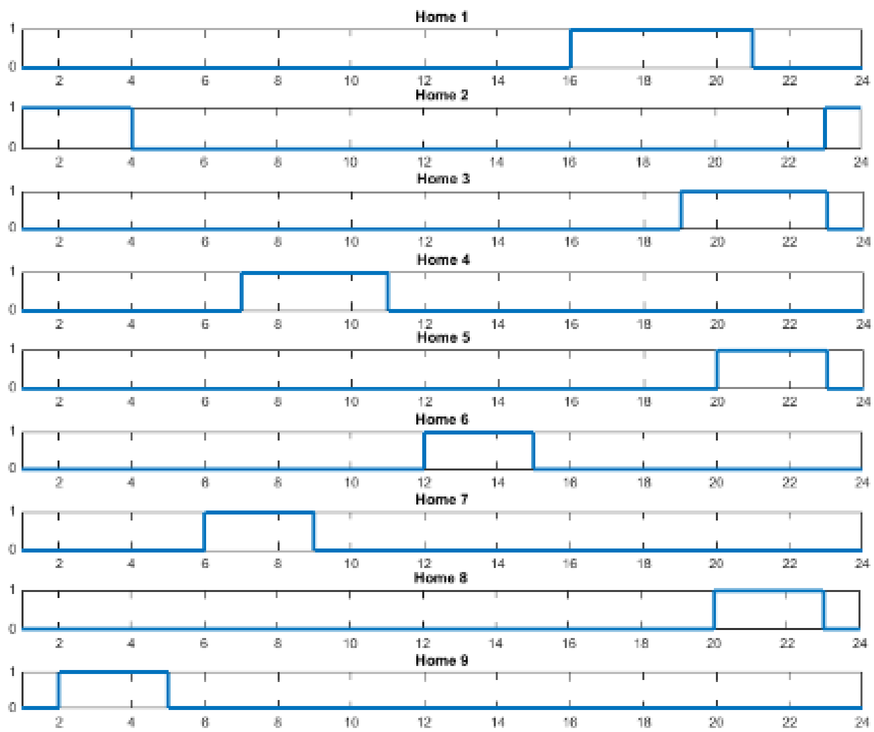
[7] J. PYPER, "It's Official. All New California Homes Must Incorporate Solar," greentechmedia, 2018. [Online]. Available: https://www.greentechmedia.com/articles/read/solar-mandate-all-new-california-homes#gs.h2lwiSJC.

**Figure 42: Block Load and Phovoltaic Profile – 5/15/2014**




Source: UC Irvine

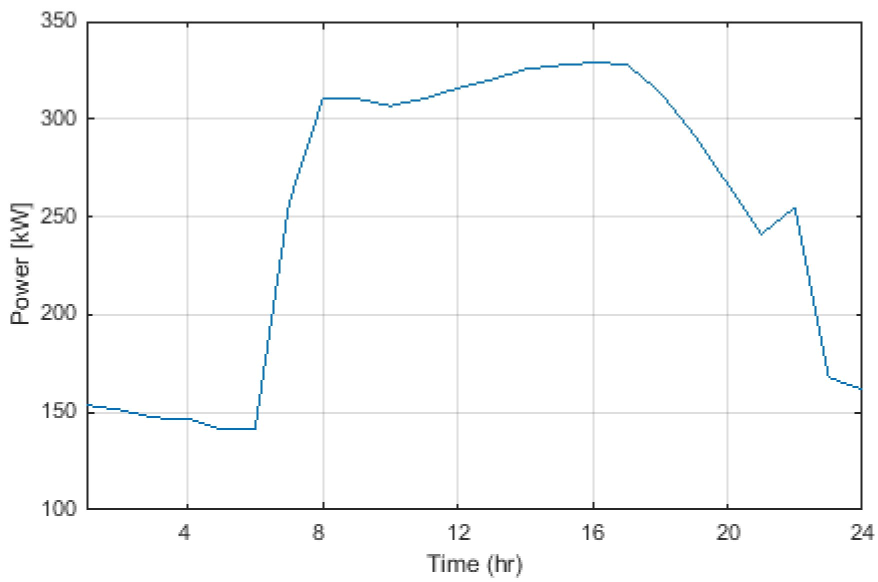
**Figure 43: Average Electric Vehicle Charging Schedule per Home**




Source: UC Irvine

For the commercial section of the circuits, the load data from the South Coast Air Quality Management District building obtained from the CEC funded project[8] were used. The load data from 2007 to 2009 were averaged as shown in Figure 44, and this profile was used throughout the commercial load points in the circuits. The pre-set spot load embedded in the CYME model was used as a scaling factor for these commercial loads because the actual building type and load data are not available for these sections of the circuits.

**Figure 44: Averaged Commercial Building Profile South Coast Air Quality Management District**




Source: UC Irvine

With this set up, the total load at the substation was within a reasonable range compared to the actual load data observed and collected at the substation.

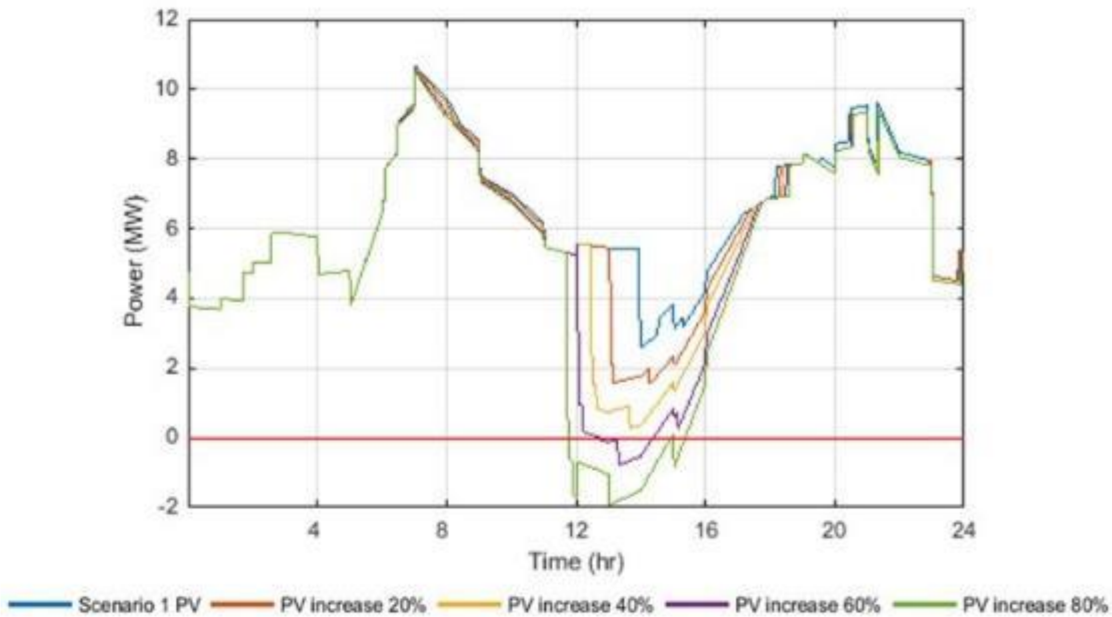
## Residential Energy Storage Units

In the RESU scenarios, each household was equipped with a 4kW/10kWh battery energy storage on the customer side of the meter. The "mode" (e.g. PV Capture, time-based load shift) of the battery operation was controlled and set by the GMC at the substation and all the RESUs were in the same mode to reduce the number of variables and simulate a practical scenario. PV capacity was increased in 20% increments until 80% which equates to about 7kW for each home. As the PV and RESU for each home are tied to a single inverter, the inverter size also increased with the installed PV capacity. PV Capture mode was selected by the controller for all simulations in order to

[8] Akbari, A., Carrera-Sospedra, M., Hack, R., McDonell, V., & Samuelsen, S. "FINAL PROJECT REPORT REALISTIC APPLICATION AND AIR QUALITY IMPLICATIONS OF DISTRIBUTED GENERATION AND COMBINED HEAT & POWER IN California Energy Commission," 2015.

minimize grid import in order to reduce costs and maximize use of DERs. Figure 45 shows the total power profile at the substation, both circuits A and B, with different PV capacities, and Figure 46and Figure 47 show the two circuits separately. In all three figures, the "duck curve"[9] can be identified which refers to the dip in the middle of the day when PV production is at its highest and the steep ramping in the afternoon.

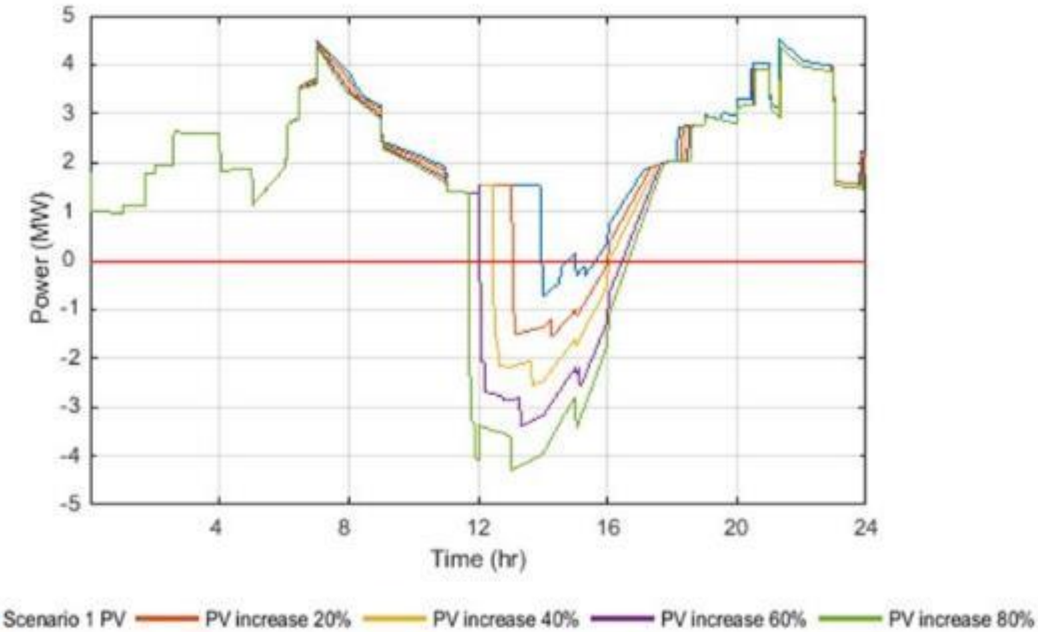
**Figure 45: Total Power Profile at Substation**




Source: UC Irvine

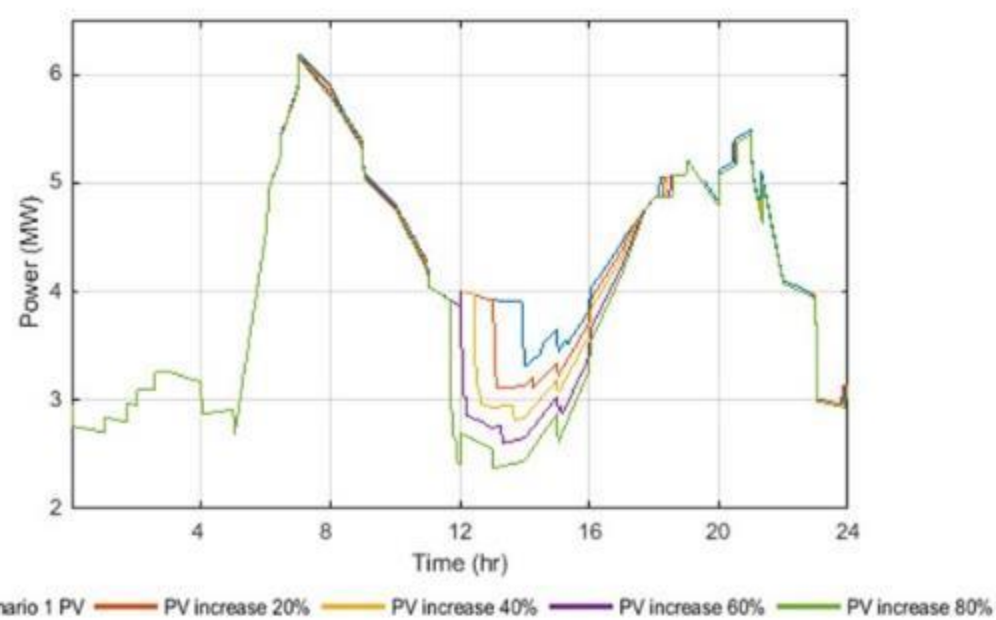
[9] P. Denholm, M. O'Connell, G. Brinkman, and J. Jorgenson, "Overgeneration from Solar Energy in California. A Field Guide to the Duck Chart," November, 2015.

**Figure 46: Circuit A Power Profile at Substation**




Source: UC Irvine

**Figure 47: Circuit B Power Profile at Substation**




Source: UC Irvine

The two circuits consist of different building/load types as depicted in load profiles in Figure 46 and Figure 47. Circuit A is mainly composed of residential loads with PVs and RESUs, whereas Circuit B is mainly composed of commercial loads, with PV only on 10 buildings and no RESUs. For that reason, circuit A exports electricity to the grid during the day as the PV capacities of the homes are increased to simulate and assess the effects of the RESU in increasing renewable DER penetration. Circuit B shows a “dip” in net load during the day as well, but it does not result in export to the grid since it does not have a high penetration of DERs. Table 5 lists the results of the simulations which shows that addition of RESUs increase the PV hosting capacity of the circuits. This table also shows voltage violations at some nodes within the systems at 80% PV capacity increase. For maximum PV, the PV capacity at the nodes with voltage violations were reduced until there were no more violations. Voltage violations (>1.05p.u) at 5 nodes close to the substation were also identified as shown in Figure 48. Voltage rise can be caused by two factors, reverse power flow and decrease in line impedance. Due to the over generation at peak PV production, as shown in Figure 49, it is expected that the voltage rises beyond 1.05p.u. around the nodes closer to the substation, since the base voltage is higher near the substation than the node points further away from the substation. This is depicted in Figure 50and Figure 51, the voltage profiles presented for the Scenario 1 PV and max case PV. In both figures, there are differences in the voltage profiles for the closest and furthest nodes from the substation. The decrease in voltage with the increase in distance from substation can be explained by voltage drop or line drop, a phenomenon in circuits due to line current and line impedance.

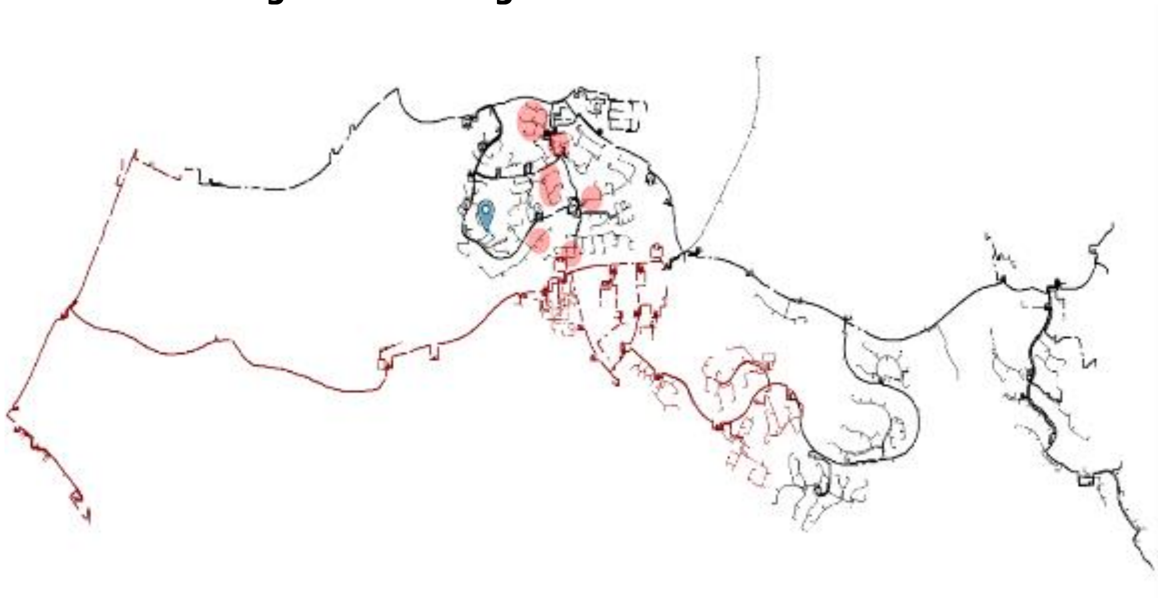
**Table 5: Result of Simulations – Residential Energy Storage Unit**

| PV Increase (%) | Voltage Violations | Total PV Capacity (MW) |
|---|---|---|
| 0% (Scenario 1) | None | 9.89 |
| 20% | None | 11.342 |
| 40% | None | 10.129 |
| 60% | None | 12.789 |
| 80% | Yes, 5 Nodes | 15.683 |
| Max | None | 15.29 |

**Total Battery Capacity: 8.439MW/21.097MWh**

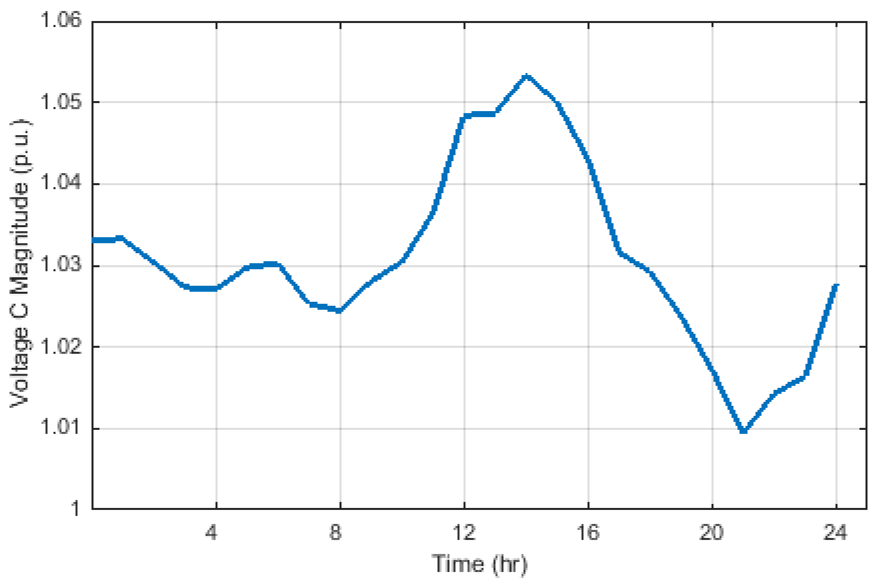
Source: UC Irvine

**Figure 48: Voltage Violation Node Location**



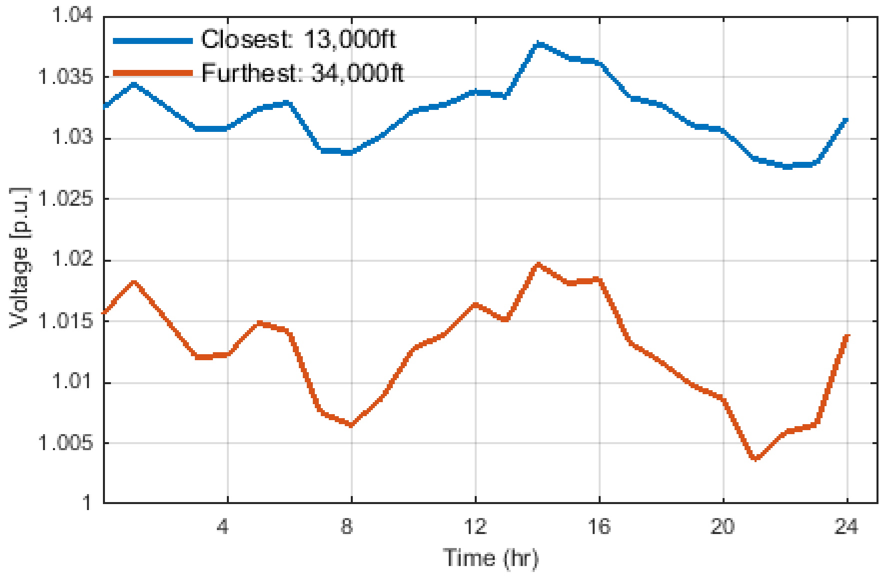
Source: UC Irvine

**Figure 49: Over Voltage at Node**



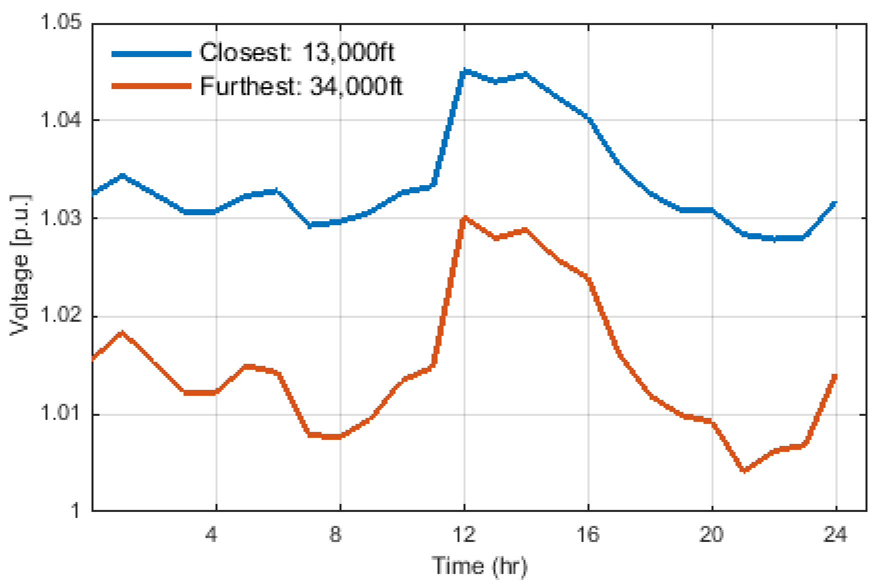

Source: UC Irvine

**Figure 50: Voltage Profile for Base Case Photovoltaic at Two Nodes**




Source: UC Irvine

**Figure 51: Voltage Profile for Max Photovoltaic Increase at Two Nodes**




Source: UC Irvine

## Community Energy Storage

In this scenario, each block (corresponding to each transformer) was equipped with a 25kW/50kWh battery energy storage (Community Energy Storage or CES). The operation of these resources was controlled by the GMC. PV capacity was increased in the same manner as the RESU scenarios. The initial conditions for the two CES modes are shown in Table 6 and Table 7. The time intervals for Mode 1 were selected based on the load stress at the transformer and the load limiting set points were selected in order to reduce peak loads at the transformer node in order to relieve stress on the infrastructure and assets. Similar to the RESU simulations, Mode 0, load limiting mode, was selected by the controller during the simulations to minimize grid import and reduce operation costs.

**Table 6: Community Energy Storage Mode 1, Time based Permanent Load Shifting**

| Charging Time Interval | Discharging Time Interval |
|---|---|
| 1:00 ~ 4:00 | 17:00 ~ 22:00 |

Source: UC Irvine

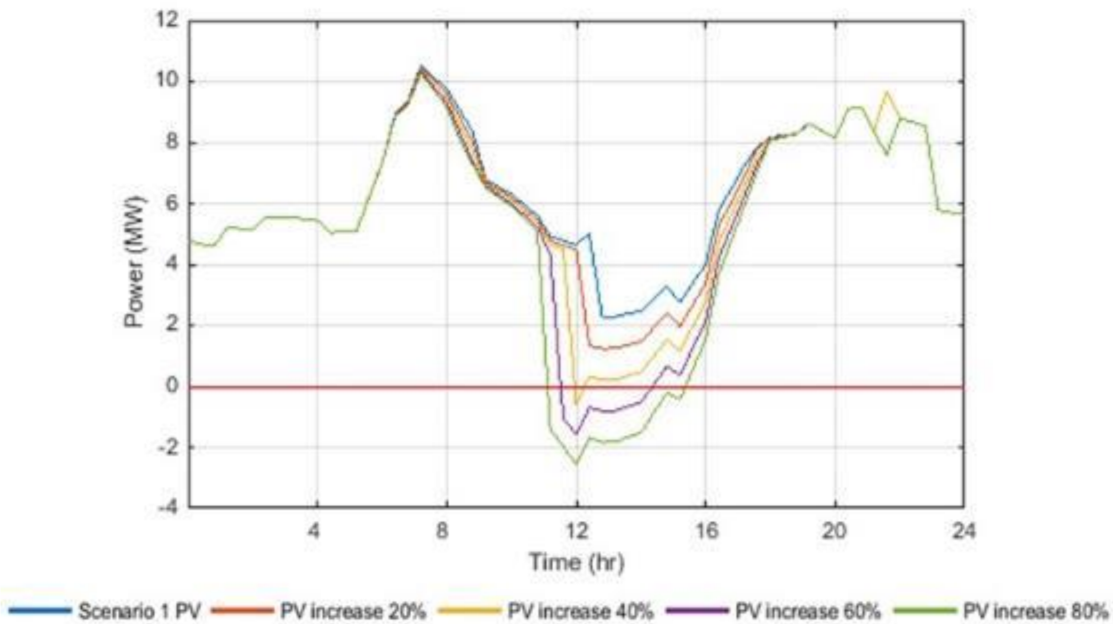
**Table 7: Community Energy Storage Mode 0, Load Limiting**

| Load Limit (kW) | Generation Limit (kW) |
|---|---|
| 5 | 0 |

Source: UC Irvine

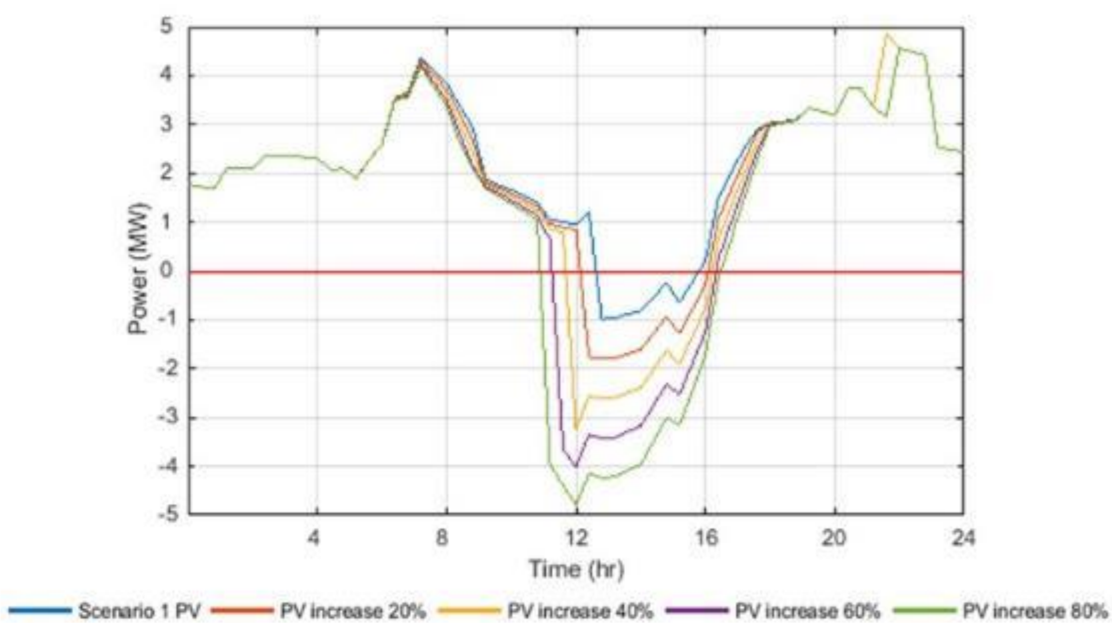
Figure 52, Figure 53, and Figure 54 show the power profiles at the substation with different PV capacities with CES, for Total, as well as circuit A, and circuit B separately. Similar to the RESU scenarios, the net load at the substation resembles the famous duck curve showing that addition of PV even with energy storage integration exacerbates the duck curve. As previously mentioned, because most of the residential housing is on circuit A, the impact of PV increase is more visible in Figure 53 associated with circuit A compared to circuit B. Due to the difference in the battery capacity, circuit A starts exporting electricity to the grid at 40% PV increase compared to 60% PV increase associated with the RESU scenario.

## Figure 52: Total Power Profile at Substation



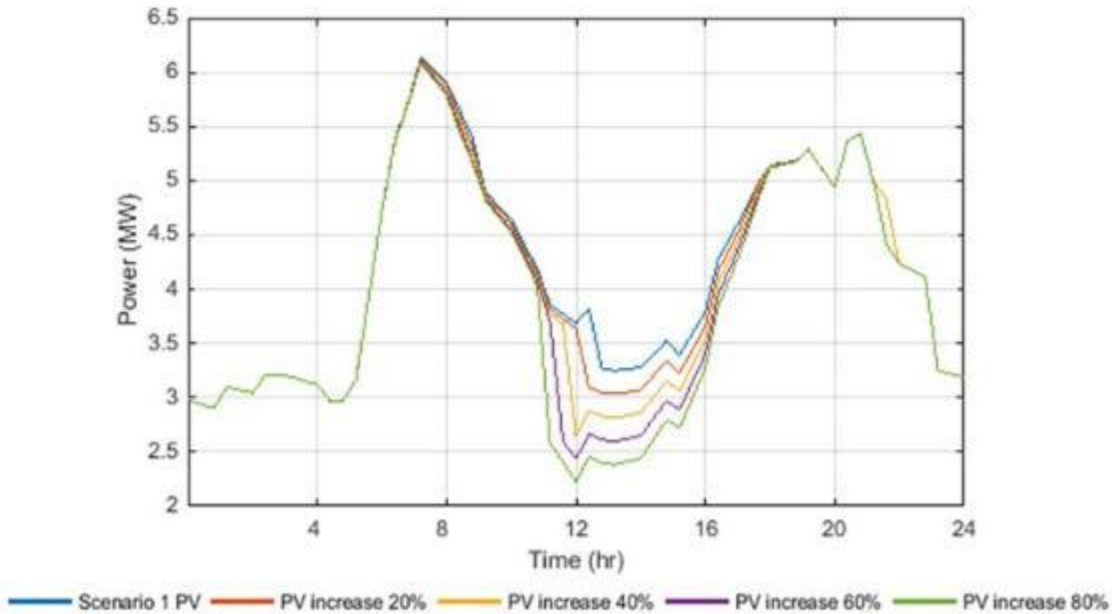

Source: UC Irvine

## Figure 53: Circuit A Power Profile at Substation




Source: UC Irvine

**Figure 54: Circuit B Power Profile at Substation**




Source: UC Irvine

Table 8 lists the results for each simulation. Unlike the RESU scenarios where there were no voltage violations until 80% PV increase, in CES scenario, over voltage (>1.05p.u.) observations start at 40% PV increase.

**Table 8: Result of Simulations – Community Energy Storage**

| PV Increase (%) | Voltage Violations | Total PV Capacity (MW) |
|---|---|---|
| 0% (Scenario 1) | None | 9.89 |
| 20% | None | 11.342 |
| 40% | Yes, 1 nodes | 10.129 |
| 60% | Yes, 9 nodes | 12.789 |
| 80% | Yes, 14 nodes | 15.683 |
| Max | None | 14.89 |

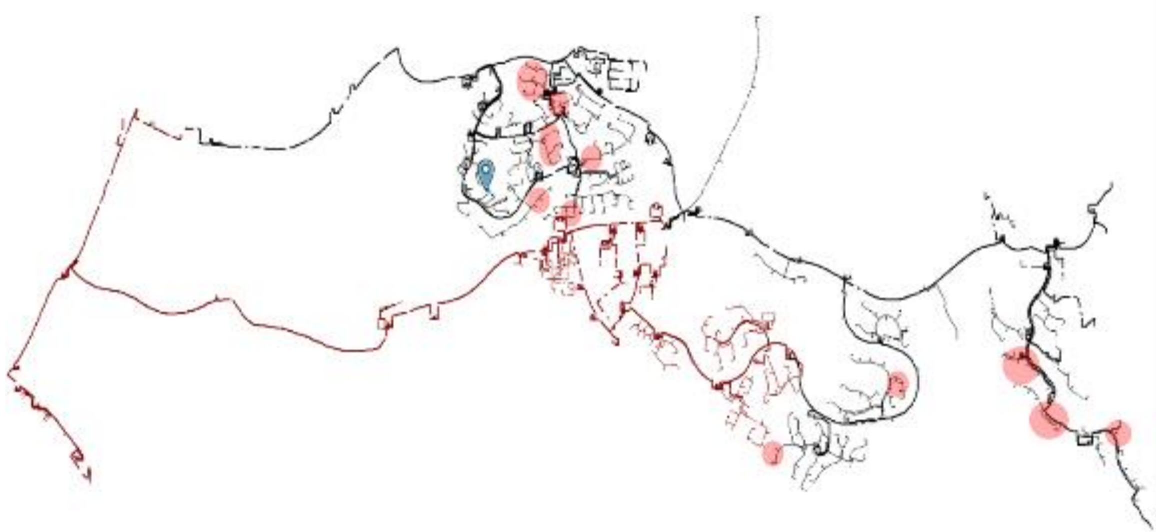
**Total Battery Capacity: 5.1MW/10.2MWh**

Source: UC Irvine

Figure 55 shows the distance and aggregated PV capacity at the node points with voltage violations at 75% PV increase. Voltage violations occurred mostly at the node points close to the substation as indicated in red. For maximum PV, the PV capacity at the nodes with voltage violations was reduced until there were no more violations as shown in Figure 56 and Figure 57. The overall model was updated accordingly to reflect these changes. Figure 58 shows the voltage profiles at the closest and furthest nodes from the substation for maximum PV penetration.

The voltage violation node points near the substation were the same as the RESU scenario, however, in the CES scenario, additional violation node points are present near the end of the distribution circuit. Along with the closest node having the highest voltage rise rate shown from section 0, this shows that the voltage rise rate was also high with high penetrations at the end of the distribution line. This confirms the findings from the ideal four bus model study included in the California Solar Initiative final report[10] performed by Advanced Power and Energy Program which studied the voltage rise rate for high PV penetration at different locations in the distribution system: beginning, middle and end, and concluded that high PV penetration fixed at the end point of the distribution circuit results in the highest voltage rise rate. Therefore, high voltage rises at node points near the substation and far node points of the substation are as expected.

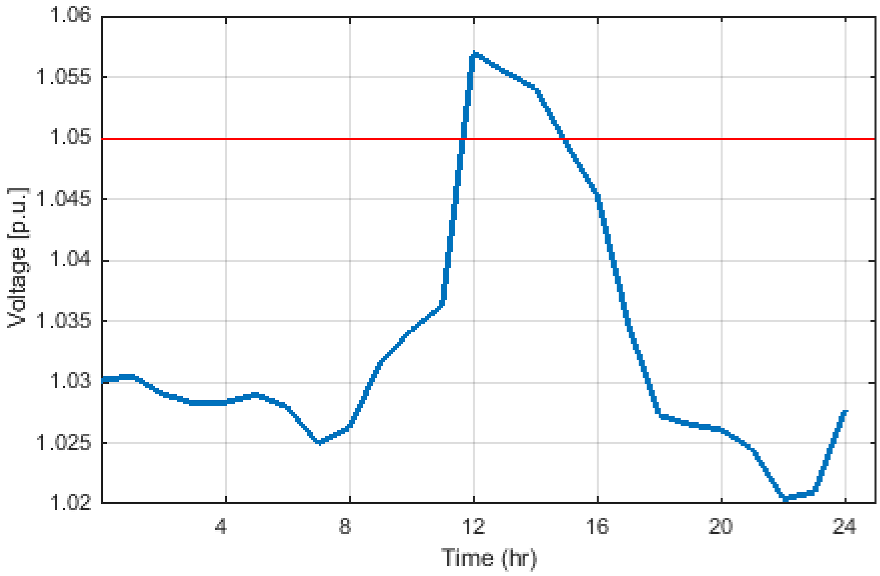
**Figure 55: Voltage Violation Node Location**



Source: UC Irvine

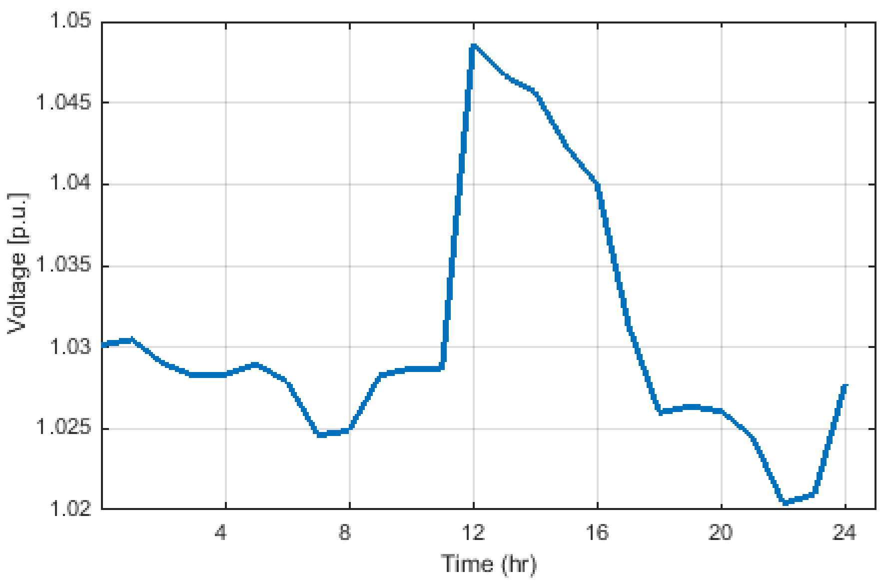
[10] Final Report, "California Solar Initiative RD & D Program Process Evaluation," 2017.

**Figure 56: Overvoltage at Node**



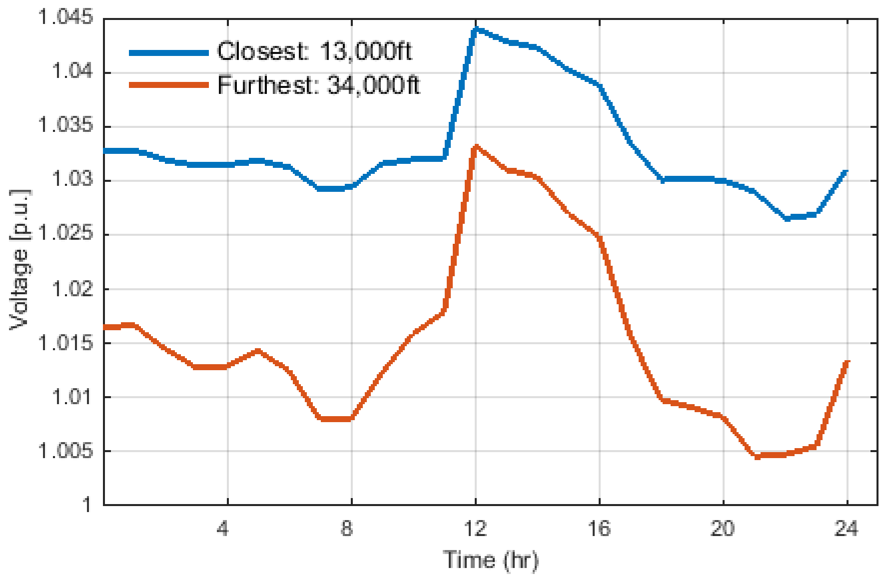

Source: UC Irvine

**Figure 57: Voltage at Node with New Photovoltaic Penetration**




Source: UC Irvine

**Figure 58: Voltage Profiles for Max Photovoltaic Penetration**



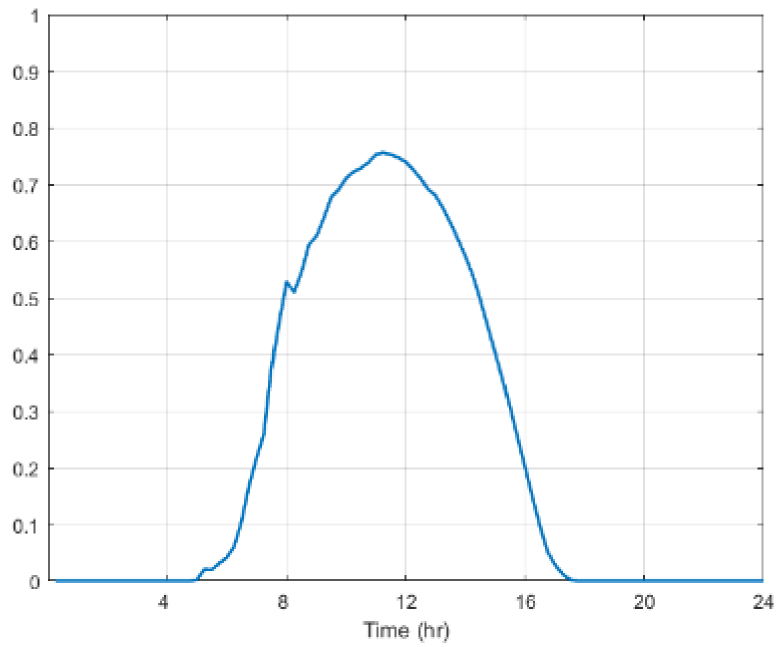

Source: UC Irvine

From the results shown in Table 5 and Table 8, it is concluded that both RESU and CES scenarios result in almost the same PV capacity (12.6 MW vs 12.2 MW, respectively); however, this PV penetration is achieved in the CES scenario with an overall 5.1 MW/10.2 MWh battery energy storage compared to 8.4MW/21.1MWh in the RESU scenarios. This result demonstrates that the same PV penetration can be achieved less expensively in the CES scenario due to less energy storage in these scenarios reducing capital costs significantly.

## Simulations with Various Photovoltaic Profiles

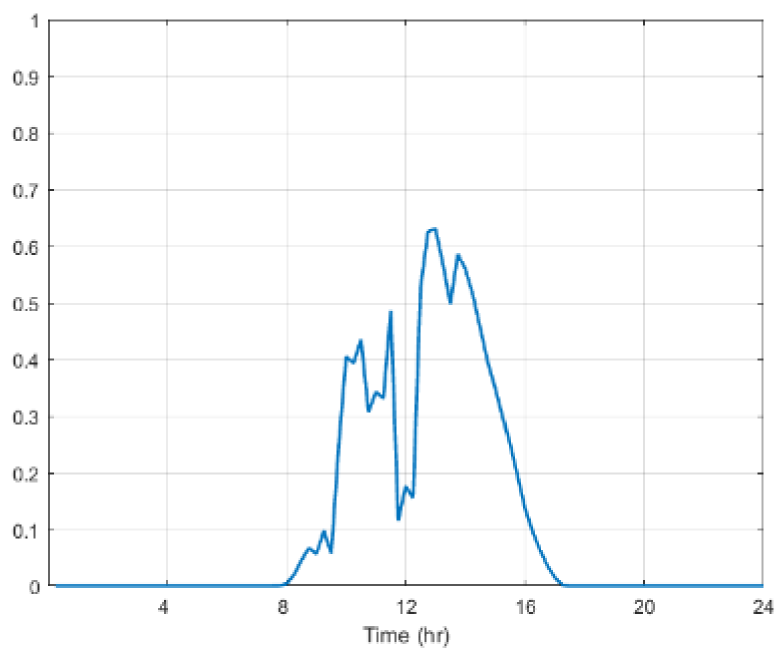
After running simulations for each scenario with one profile, different PV profiles with different resolutions and associated with different days were also simulated in order to assess the sensitivity of the outcomes to the inputs. To this end, PV data collected across University of California Irvine- which is adjacent to the ISGD community- were used to develop two different types of PV profiles: 1) high PV day on 4/16/2014 (Figure 59), and 2) intermittent and cloudy PV day on 1/10/14 (Figure 60), all with 15 min temporal resolution. The impacts of data with higher temporal resolution were investigated as well as the impact of PV intermittency especially on a cloudy day. These new PV profiles were uploaded to the model at the max PV case determined from the RESU and CES simulations previously discussed.

**Figure 59: Normalized University of California Irvine Photovoltaic Profile – High Photovoltaic Day (4/16/14)**




Source: UC Irvine

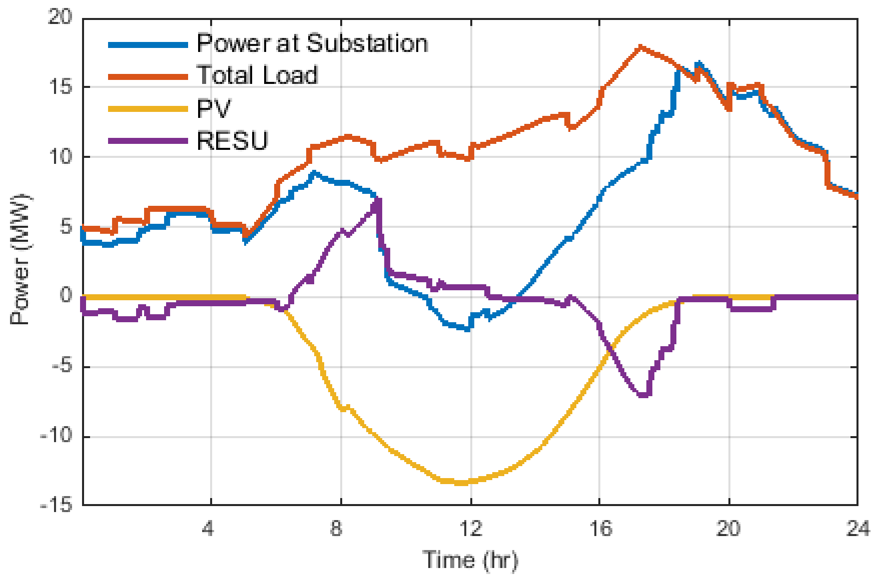
**Figure 60: Normalized University of California Irvine Photovoltaic– Intermittent Photovoltaic PV Day (1/10/14)**




Source: UC Irvine

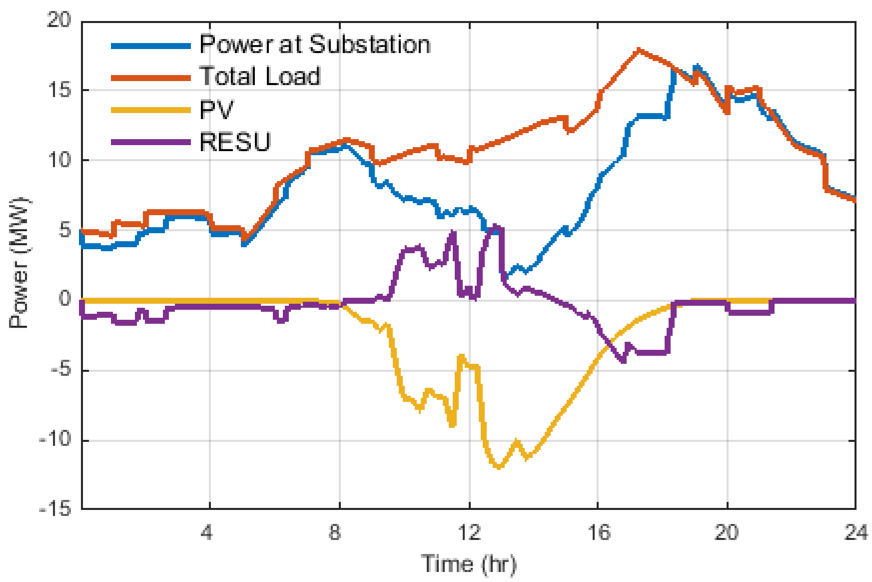
The results of the simulations for the RESU and CES cases were similar. Figure 61 to Figure 64 show the power profiles at the substation for various PV profiles studied.

**Figure 61: Power Profile with High University of California Irvine Photovoltaic Profile – Residential Energy Storage Unit**



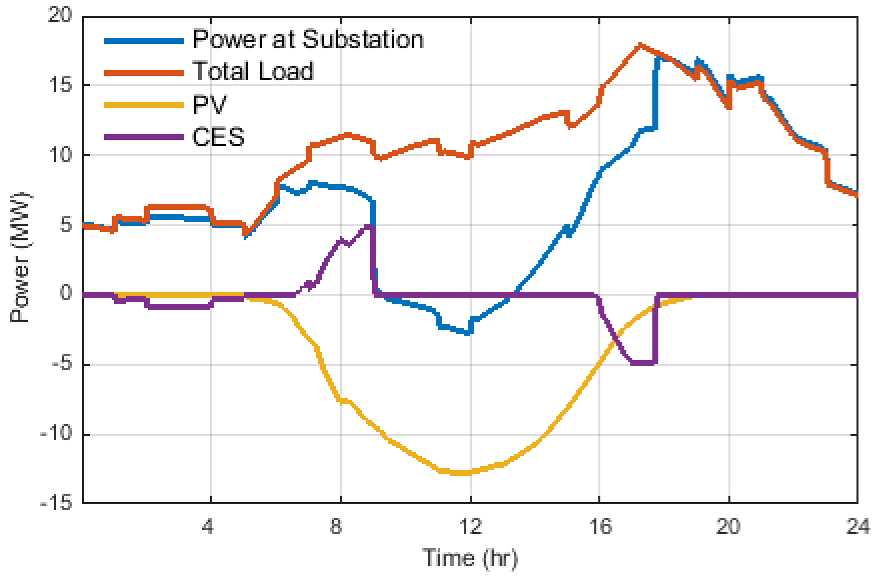

Source: UC Irvine

**Figure 62: Profile with Intermittent University of California Irvine Photovoltaic Profile – Residential Energy Storage Unit**



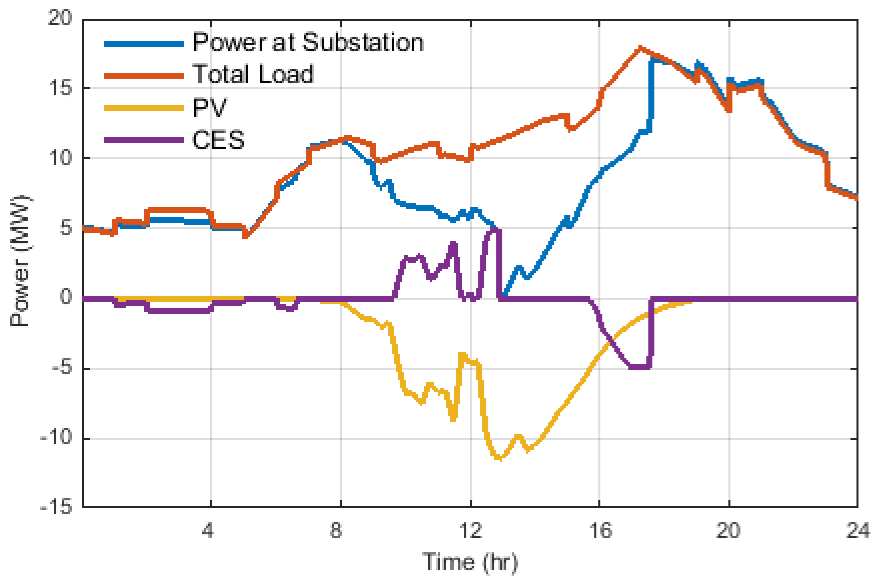

Source: UC Irvine

**Figure 63: Power Profile with High University of California Irvine Photovoltaic Profile – Community Energy Storage**




Source: UC Irvine

**Figure 64: Power Profile with Intermittent University of California Irvine Photovoltaic Profile – Community Energy Storage**



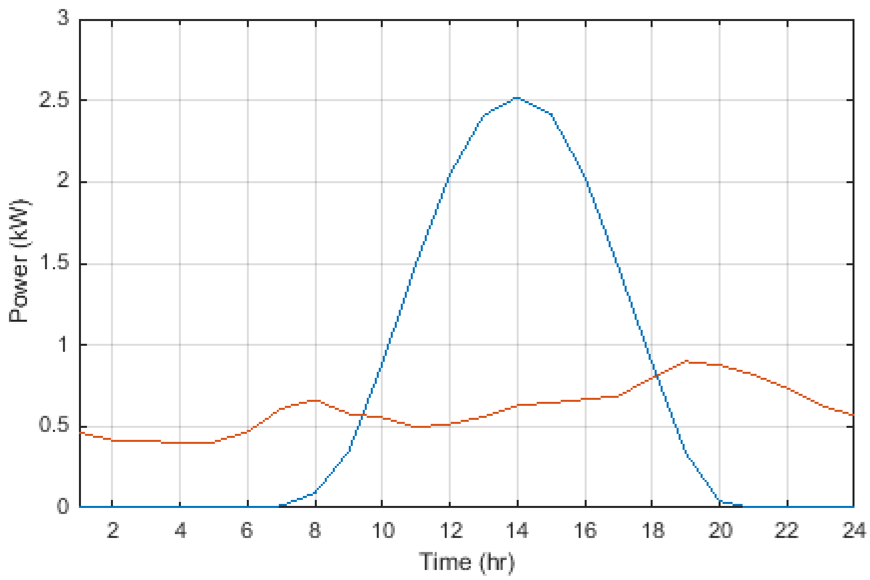

Source: UC Irvine

After running all four simulations, 4 nodes from the CES scenario and 9 nodes from the RESU scenarios experience over voltages at high PV penetrations. These nodes are the same nodes seen for the previous CES scenarios from section 0 with ISGD PV profile data.

## Renewable Penetration

In order to determine the renewable penetration (based on energy), the averaged load and PV data are used for one whole year of the ZNE block (Figure 65). The overall power seen at the substation, was comparable to the actual substation power data recorded during the ISGD project.

**Figure 65: Annual Average Load and Photovoltaic Profile**




Source: UC Irvine

The $Renewable\ Penetration_{Total}$ is 39% (associated with 15.29 MW of PV) when all the PV generated electricity was used and not curtailed, equation 5.1. However, the two circuits are not able to consume all the PV generated electricity and exported to the grid as shown in
Figure 45 and Figure 52. Exporting can be limited due to the interconnection agreements, and as the exporting hours coincide with the belly of the "duck curve," it is likely that the grid is unfavorable of such export, resulting in negative prices or curtailment.

$$Renewable\ Penetration_{Total} = \frac{\text{Total Annual PV Generation}}{\text{Total Annual Load}} \tag{6.1}$$

To determine the renewable penetration solely for the two circuits, taking into account the curtailment, the below equation was used.

$$Renewable\ Penetration_{Substation} = \frac{\text{Total PV Generation} - \text{Curtailed Energy}}{\text{Total Load}} \quad (6.2)$$

As shown in Table 9, the no storage case has over a 6.4 MWh of curtailed energy and the renewable penetration is 35.8%. By adding energy storage, the renewable penetration increases to 37.5% for the RESU case and 35.3% for the CES case. For both cases, there was only a slight difference in the maximum total PV capacity which resulted in small renewable penetration difference.

**Table 9: Renewable Penetration**

| Scenario | Total PV Capacity (MW) | PV Energy for 1 day (MWh) | Curtailed Energy (MWh) | Load for 1 day (MWh) | Renewable Penetration (%) |
|---|---|---|---|---|---|
| No Storage | 15.29 (RESU) | 81.1 | 6.4 | 208.1 | 35.8 |
| No Storage | 14.89 (CES) | 78.0 | 4.7 | 208.1 | 35.2 |
| All RESU | 15.29 | 81.1 | 3.1 | 208.1 | 37.5 |
| All CES | 14.89 | 78.0 | 4.2 | 208.1 | 35.4 |

Source: UC Irvine

## Circuit Battery

A 2MW/500kWh battery energy storage was simulated at the substation, referred to as the "circuit battery" since it served the entirety of the two circuits. During the simulation, the controller set the mode of the circuit battery to mode 0, load limiting mode, in order to minimize grid import at the substation and maximize the use of DERs and reduce costs. The parameters were set as Table 10.

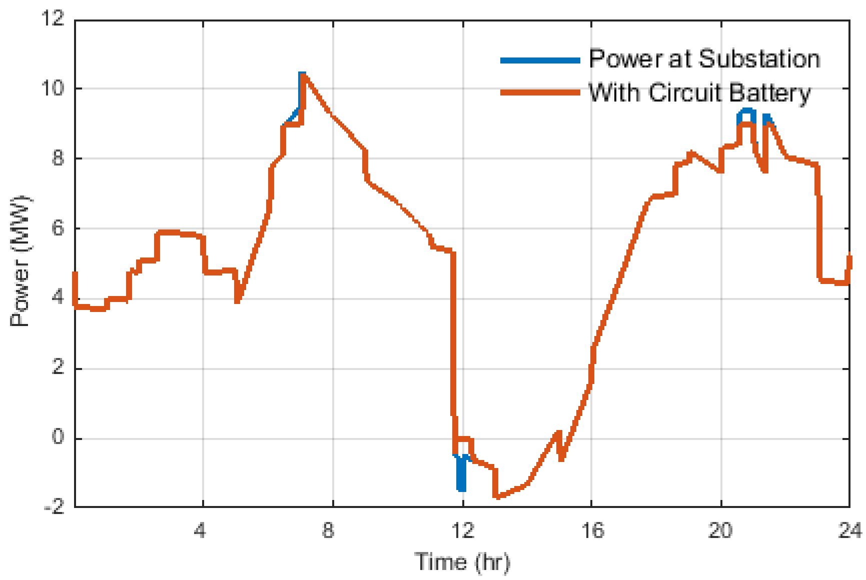
**Table 10: Circuit Battery Parameters – Mode 0**

| Parameter | Value |
|---|---|
| Initial SoC | 50% |
| Efficiency | 96% |
| Load Limit | 9 MW |
| Generation Limit | 0 MW |

Source: UC Irvine

Figure 66 shows the power profile at the substation without and without the circuit battery. Given the low energy capacity of the battery, there are minor impacts on the two circuits.

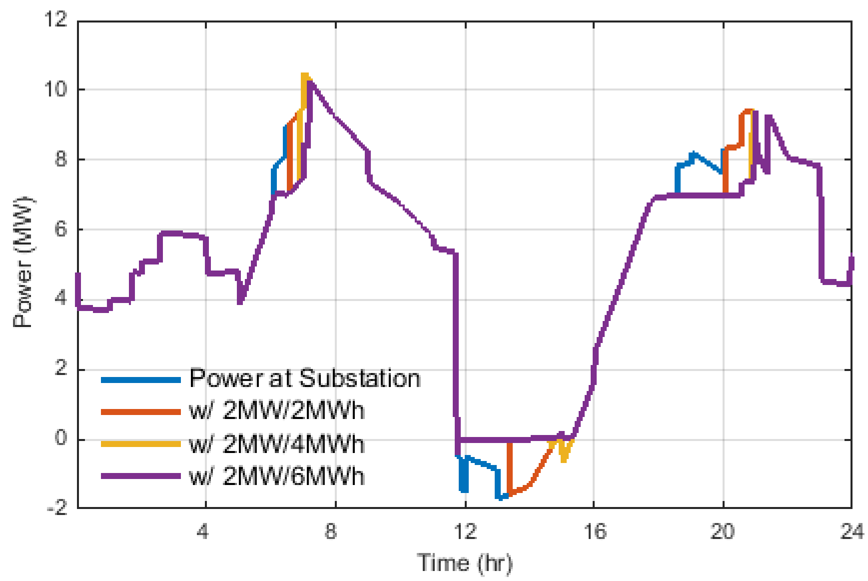
**Figure 66: Circuit Battery Impact on Power Profile**




Source: UC Irvine

To further assess the impact of a larger battery energy storage, a series of different sized batteries were simulated with a new load limiting set point of 7MW. As shown in Figure 67, 2MW battery energy storage with 2, 4, 6 MWh capacities were simulated. With the 2MW/6MWh battery, nearly zero export of electric was possible at the substation by charging the battery using all excess solar generated electricity and discharging to shave the peak loads. This can help alleviate the duck curve issues in the overall grid.

**Figure 67: Circuit Battery Impact on Substation – 2MW Battery**




Source: UC Irvine

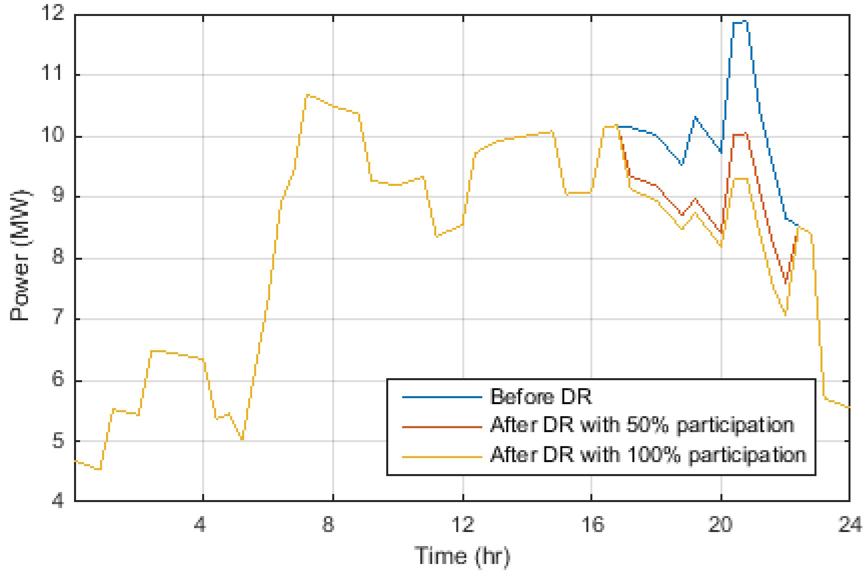
## Scenario 3

For this scenario, all homes were assumed to be equipped with smart appliances and energy management system capable of responding to DR requests. DR signals were sent to homes from the controller to resolve any system violations that occur in the system. Simulations with different DR load shed percentage, and different participation rate were conducted. The DR signal was sent from the grid operator from 5PM to 9PM. This time block is the super peak block from the CAISO Proposed TOU Periods[11] and reflects the high peak load and steep ramp up curve resulting from PV generation (the duck curve). The simulation was done on both maximum scenarios of CES and RESUs from the previous section. DR signals were sent to reduce 20% and 40% of the total load consumed from each home. Also for each corresponding percentage and signal, different participation percentage was simulated. After looking at the ISGD data for homes, it was reasonable to reduce up to 40% of the home load which is equivalent to turning off 75% of the lights and reducing the air conditioning load to half (or other combinations). For EVSEs, a DR signal of 50% reduction in charge rate was sent. Figure 68 shows the maximum CES case with 20% DR and Figure 69 shows the same case with 40% DR. It is observed that only a small difference in the load reduction occurred between 50% and 100% participation. This was due to the fact that all the homes which had the EV charging during those hours participated to reduce 50% of the EV charge capacity, and the other non-participating homes did not have EV charging

[11] "CAISO time-of-use periods analysis," 2016.

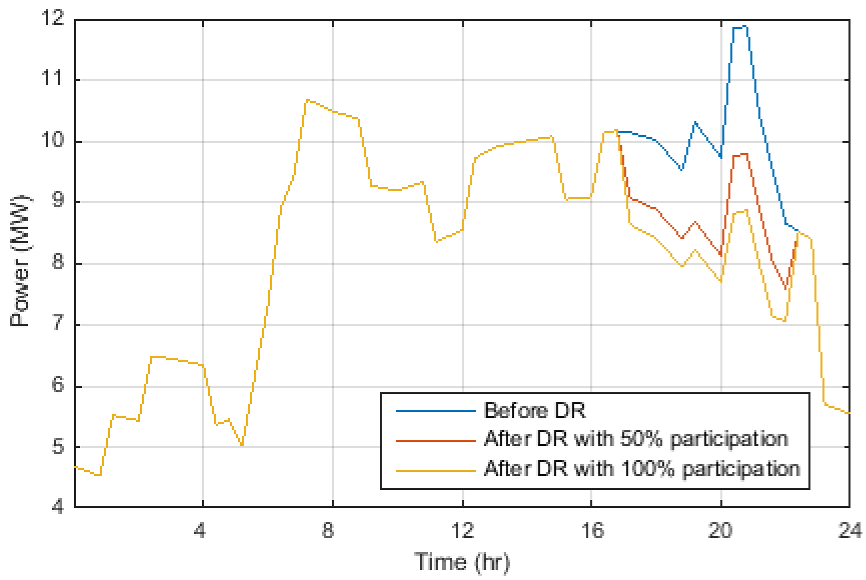
scheduled during this time. This shows that DR on EV charging, which is a large load compared to other residential loads, has a large impact on reducing load.

**Figure 68: 20 Percent Demand Response Results**



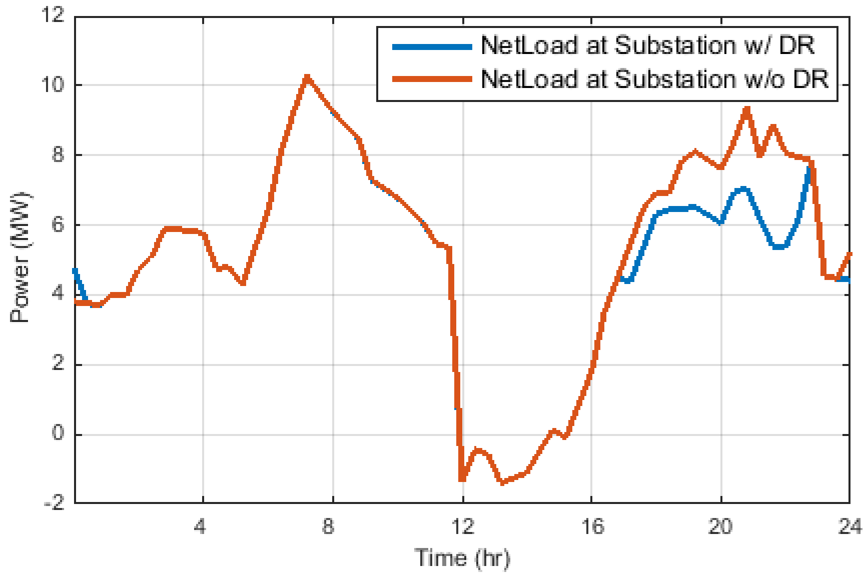

Source: UC Irvine

**Figure 69: 40 Percent Demand Response Results**




Source: UC Irvine

**Figure 70: Net Load at Substation With and Without Demand Response**




Source: UC Irvine

These results show that using DR can help relieve the ramping requirements in the duck curve in the afternoon by reducing demand during these intervals as shown in Figure 70.

## Scenario 4

In the circuit independent scenarios, the circuit was equipped with a 2MW/500kWh circuit battery and a 2.8MW PAFC at the substation with the given parameters in Table 11. The current substation does not have the required footprint to host a fuel cell of this size and a battery. However, this scenario was simulated and investigated to study the possible impacts of a fuel cell at a substation on reliability and outage reduction[12].

**Table 11: Fuel Cell Parameters[13]**

| Capacity [kW] | Ramp Up Rate [kW/s] | Ramp Down Rate [kW/s] | Base Load [%] |
|---|---|---|---|
| 400 | 10 | -20 | 56 |

Source: UC Irvine

[12] B. Shaffer, B. Tarroja, and S. Samuelsen, "Dispatch of fuel cells as transmission integrated grid energy resources to support renewables and reduce emissions," Appl. Energy, vol. 148, no. x, pp. 178–186, 2015.

[13] Clear Edge Power, "Electric Load - Following Capability of the PureCell ® Model 400 Fuel Cell System," no. January, 2013.

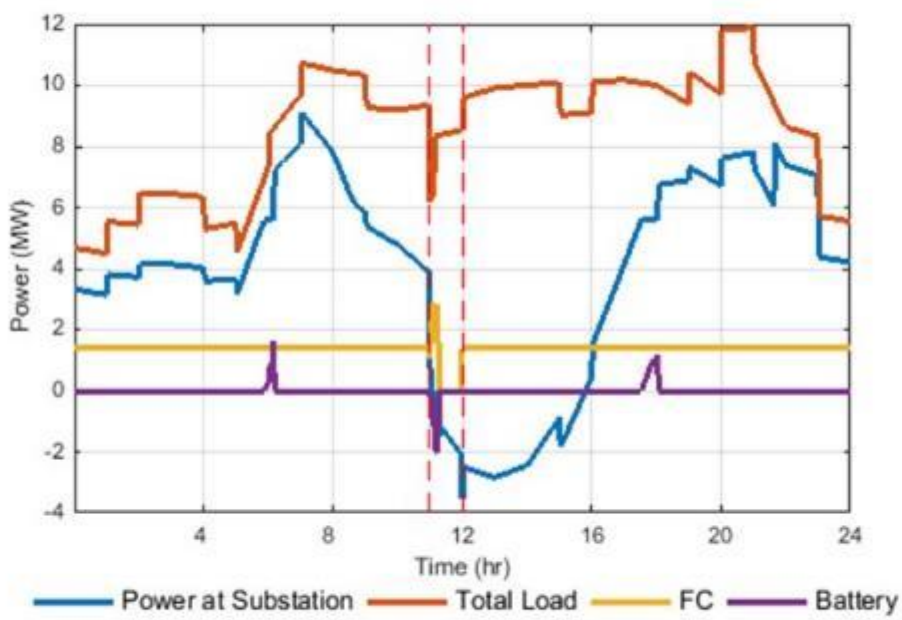
According to the annual reliability report from Southern California Edison[14], about 95% of customers experience 0~10 hours of power outage during a Major Event Day (MED). MED is a day which the daily System Average Interruption Duration Index (SAIDI) exceeds a threshold value; the days that experience severe stresses on system such as severe weather or unforeseen occurrences. To simulate such outages, an emergency signal was sent to the substation with different durations: 1hr, 5hrs, and 10hrs for both CES and RESU cases. The grid outage started at 11:00 am for the simulations for the different outage times.

Figure 71 to Figure 73 show the three simulation results for the CES cases and Figure 74 to Source: UC Irvine

Figure 76 for the RESU cases. The fuel cell was operating at 56% baseload, at its highest efficiency point[13] during normal business as usual operation, and during the emergencies followed the demand (load-following) to its best ability as explained in Section 0.

It is observed that load-shedding occurred only during a short interval, and excess PV generated electricity was exported during the 1-hour outage during 11-12pm. Should the system not be allowed to export to the grid, the PV would have to be curtailed). The 5-hour outage in Figure 72 shows similar results where all the demand load was met by DERs, except during the short interval at 11am.

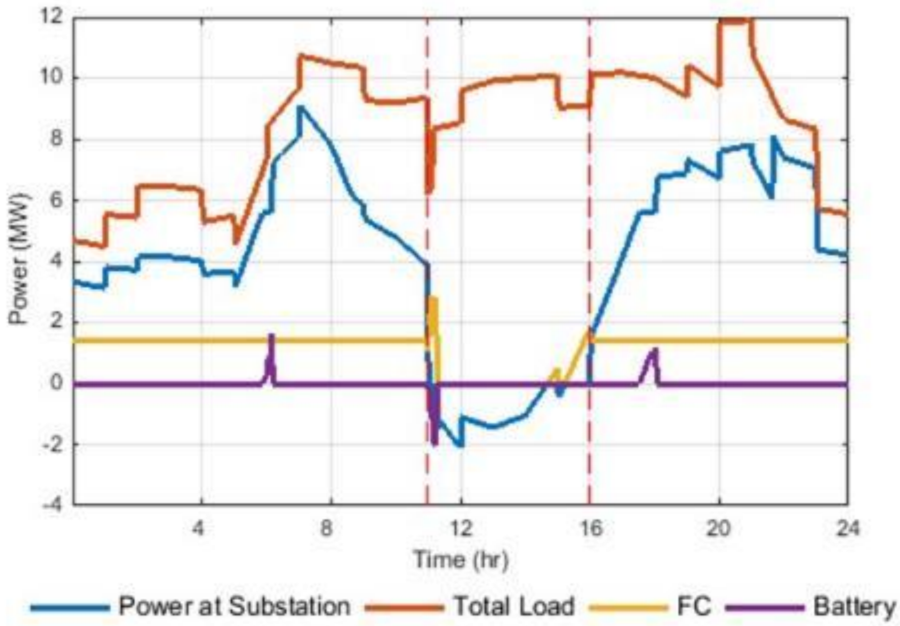
**Figure 71: Community Energy Storage Case – 1 Hour Outage**




Source: UC Irvine

[14] Southern California Edison, "Annual System Reliability Report," 2016.

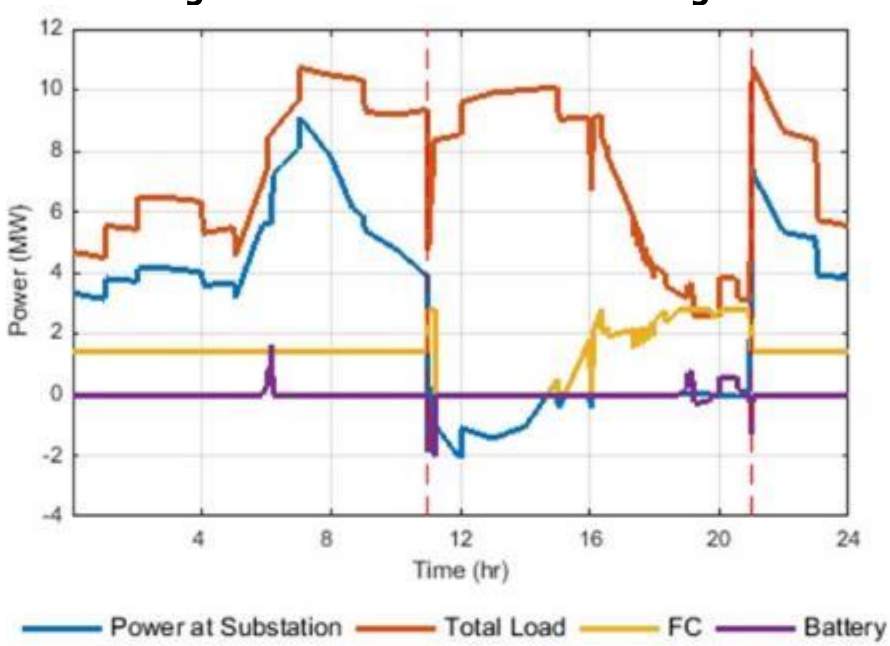
**Figure 72: Community Energy Storage Case – 5 Hour Outage**




Source: UC Irvine

During the 10 hour outage which goes on until the evening, significant load-shedding was required after 4pm to ensure supply/demand balance and system stability. About 70% of the load was dropped in order to match the local electricity generation and the demand load. While dropping this much of the electricity demand seems excessive; the alternative is for the system to experience a complete outage and lose critical loads.

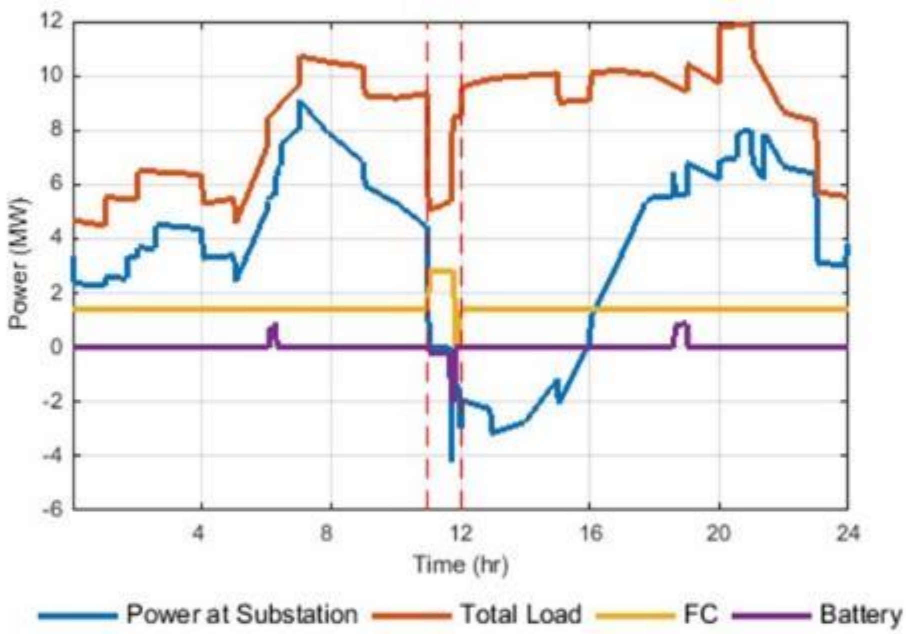
**Figure 73: CES Case – 10 Hr Outage**




Source: UC Irvine

For the RESU cases, the overall results are similar; however, due to the difference in operation and size of energy storage units, significant load shedding was required from 11am to 12pm as shown in Figure 74.

**Figure 74: RESU Case – 1 Hr Outage**

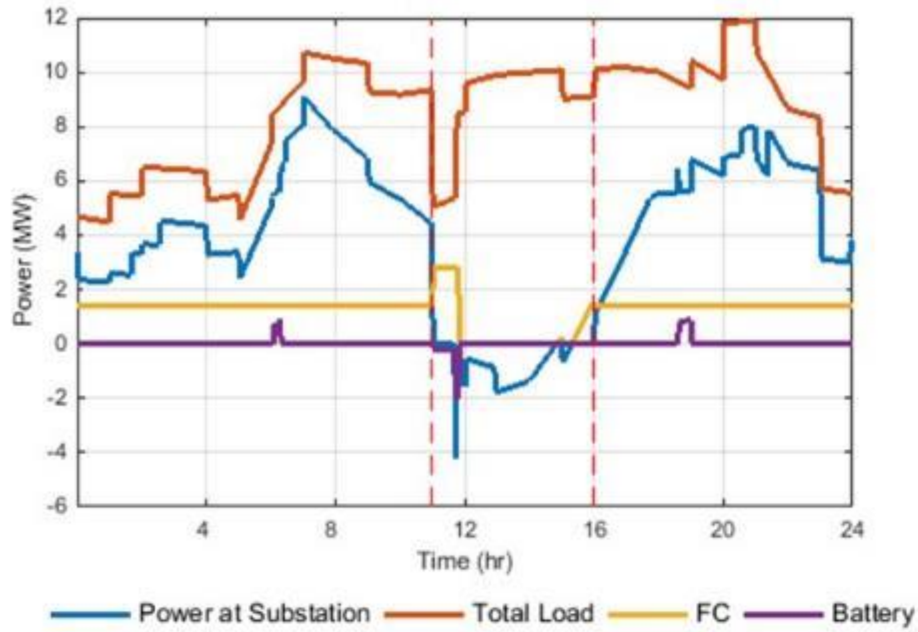



Source: UC Irvine

Both the 5 hour and 10 hour outage simulations, depicted in Figure 75 and Source: UC Irvine

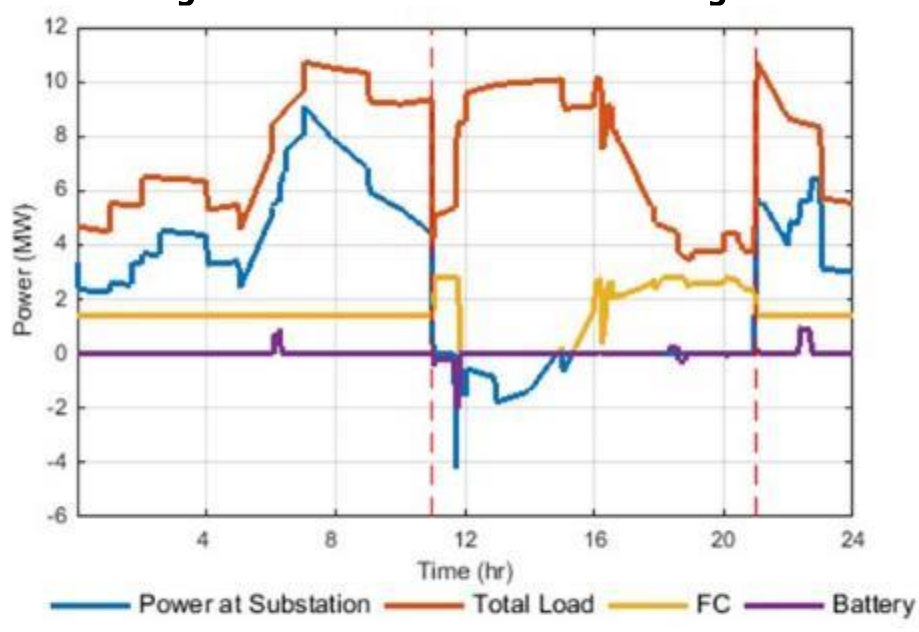
Figure 76 respectively, are similar to the CES cases requiring significant load-shedding during the evening hours when there is no PV generation and only the fuel cell and energy storage units are available for electricity generation.

**Figure 75: RESU Case – 5 Hr Outage**




Source: UC Irvine

**Figure 76: RESU Case – 10 Hr Outage**

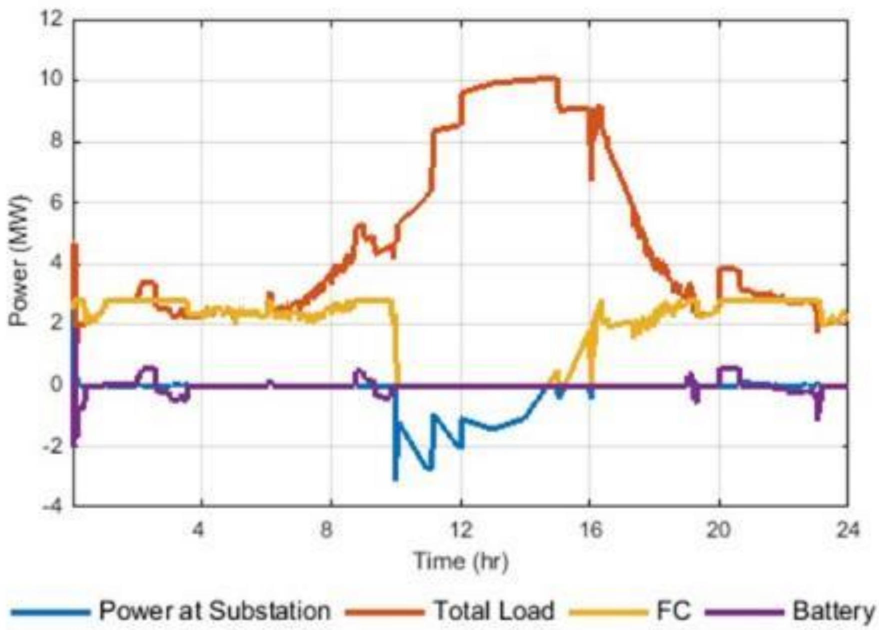



Source: UC Irvine

For a 24-hour emergency zero import situation, an emergency signal was sent to the substation and the controller switched the modes of the DERs in the circuit to accommodate the grid outage as described in Section 0 and Figure 36.

During the CES scenario simulation, the two circuits were kept "live" with heavy load shedding for periods of high loads and zero PV. Zero load was dropped and excess PV generated electricity was available during high solar hours but up to 70% load shedding was required during the evening. Figure 77 shows the 24 hour power profiles for the two circuits.

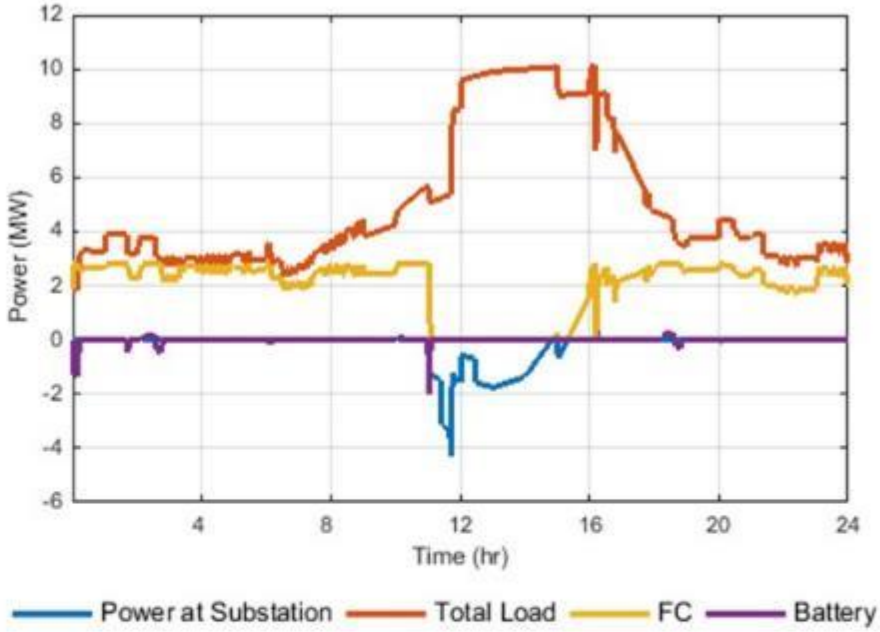
**Figure 77: CES 24 Hour Power Outage Profile**




Source: UC Irvine

For the RESU scenario, the grid was also “live” during the 24hour outage. As the controller sends each home the demand response based on the total load, the total output load is harder to manage because each home’s net load depends on the battery storage dispatch associated with that home. With the current model, the total load was managed as depicted in Figure 78. The figure shows spikes of power export due to the mismatch of the fuel cell ramp down rate and immediate load drop from DR.

**Figure 78: RESU 24 Hour Power Outage Profile**




Source: UC Irvine

# CHAPTER 6: Task 5: Retail/Distribution Market

## Electricity Markets and Market Participation for Distributed Energy Resources

The generation, transmission, distribution, and sale of electrical energy has been undergoing a major transformation. Driven by the promise of lower prices from competition, the traditional regulated monopoly, vertically integrated utility is being disaggregated into a system of competitive markets. This transformation has been taking place in three main arenas:

1. Wholesale Markets and Transmission
2. Retail Markets
3. Distribution

*Wholesale Markets* involve the sale of bulk energy (MWH) and capacity (MW) between large generators and retail Load Serving Entities (and sometimes large industrial customers). The construction and ownership of transmission lines has also been opened to competition. This has been the first and most common area for transition to a market structure. About 2/3 of US customers now receive power from wholesale markets and about 1/3 from vertically integrated regulated monopolies. While the transmission systems themselves are still mostly owned by the utilities that built them, who are referred to as Transmission Owners (TO), the transmission system and the energy/capacity markets are operated by an independent entity called either an Independent System Operator (ISO) or Regional Transmission Organization (RTO).

*Retail Markets* in many states allow customers to choose their retail Energy Services Provider (ESP) which in turn purchases energy on the wholesale market. Where this function has been separated from the regulated utility, the entity retaining ownership and operation of the physical distribution "wires" system is called the Utility Distribution Company (UDC) or Distribution Owner (DO). Metering and billing can also be separated or retained by either the ESP or UDC. If a customer does not pick an alternative ESP, the UDC fills this role as a default Provider of Last Resort (POLR) also known as Standard Offer Service (SOS) or "bundled service." Retail markets are available in thirteen states and the District of Columbia. They also exist in the UK and some other foreign countries. Retail choice is most used by industrial customers, then by commercial customers, and least (often none) by residential customers. This makes sense since larger consumers have more bargaining power and regulators often artificially keep rates down for residential customers (voters). Benefits to consumers have been marginal or unclear, in general.

A more recent trend has been to try and create a *Distribution Market* to increase the opportunity for DERs including generation, storage or demand response, to sell to other parties. Three subcategories of distribution markets are:

1. Value of DER Markets, where DER sells services to the UDC in lieu of traditional wires solutions,
2. Aggregator Role, where the Distribution System Operator (DSO) to aggregate DER output and sell it into the wholesale market, and
3. Direct Access, where DER can sell to any customer over the distribution system. As in transmission, the physical distribution system is owned by the UDC/DO which is a regulated monopoly utility. The DSO would have to operate a market and oversee distribution planning to ensure transparency and fairness. Whether the UDC/DO can perform these DSO functions with regulatory oversight or whether an independent DSO (IDSO) similar to the ISO/RTO model is up for debate.

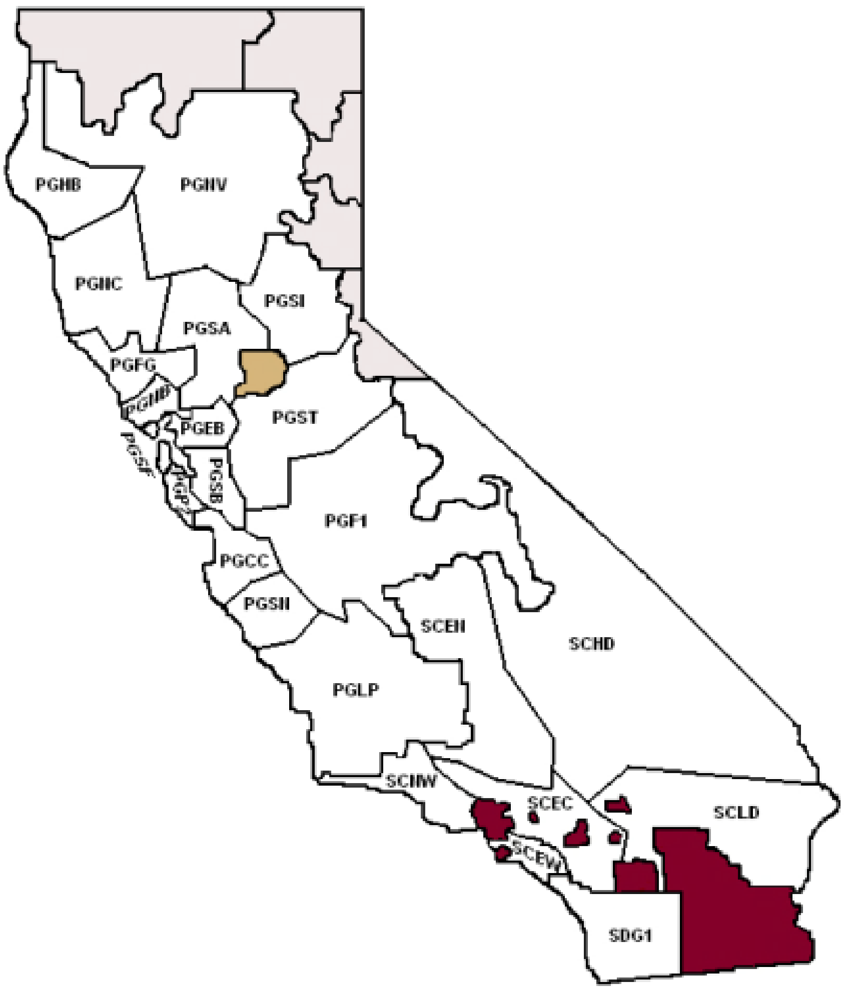
## DER Wholesale Market Participation Benefits (Existing Opportunities)

If a resource is connected to the transmission system, it can connect to CAISO grid (see Appendix B for details) and go through new resource implementation and participate in CAISO markets that it qualifies for via a scheduling coordinator.

For resources that are in the distribution system (and sub-transmission system), CAISO accepts bids for Energy and Ancillary Services from Distributed Energy Resource Aggregations only if they are represented by a Distributed Energy Resource Provides (DERP) which has entered into a Distributed Energy Resource Provider Agreement with the CAISO to comply with all applicable provisions of the CAISO Tariff. A Distributed Energy Resource Aggregation consists of 1 or more DERs and it need to be at least 0.5 MW, and it must be located in a single Sub-LAP (Load Aggregation Point). A map of the sub-LAPs is shown in Figure 79. If DERs are located at different P-Nodes, the Distributed Energy Resource Aggregation needs to be smaller than 20 MW. Each Distributed Energy Resource should then provide a net response at P-Node (or P-Nodes) in a single Sub-LAP consistent with CAISO dispatch instructions. Note that a DER participating in a Distributed Energy Resource Aggregation cannot participate in a retail net metering program or participate in CAISO markets separate. Thus, both net-metering and wholesale market participation cannot be counted simultaneously towards the benefits of DERs.

In order to access the P-Nodes, transmission system and ultimately CAISO markets, DERs need to use the distribution system and the infrastructure owned by the utility and thus they require to have a WDAT(details included in Appendix B). DERs must be directly metered with a meter complaint with the utility company for the purpose of settlement. However, if the DER aggregation is larger than 10MW or it provides ancillary services, the information should be provided to the CAISO EMS through telemetry complying with CAISO standards for direct telemetry. In summary, for DERs to participate in CAISO wholesale markets, they need to have a WDAT with the utility and be part of a Distributed Energy Resource Aggregation represented by a DERP and the bids need to be submitted by a scheduling coordinated. Details of requirements and responsibilities of DERPs, Distributed Energy Resource Aggregations, and other entities can be found in CAISO Tariff[15].

**Figure 79: CAISO Sub-LAP Map**




Source: California Independent System Operator, Proxy Demand Resource (PDR) &Reliability Demand Response Resource (RDRR) Participation Overview.
https://www.caiso.com/Documents/PDR_RDRRParticipationOverviewPresentation.pdf

[15] California Independent System Operator. California Independent System Operator Corporation Fifth Replacement FERC Electric Tariff. November 2018. http://www.caiso.com/Documents/ConformedTariff-asof-Nov15-2018.pdf

There are several CAISO products available for Distributed Energy Resource Aggregation that include not only distributed generation but also energy storage and controllable loads. One of these products is Non-Generating Resources or NGRs. NGRs can provide all services. (Note that CAISO has another resource model for storage, *Pump Storage,* as well which does not apply to the discussions in this section).

Others product available are Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR). PDG can provide Energy, Non-Spinning Reserve, and Residual Unit Commitment (RUC), while RDRR can provide only Energy. Note that these two products are both similar to demand response and thus reduce/curtail demand and thus do not inject any power into the system and thus will not require a WDAT with the utility. PDRs can bit into day-ahead energy market, day-ahead and real-time non-spinning reserve market and 5-minute real-time energy market and must have a minimum load curtailment of 100kW for energy market and 500MW for non-spinning reserve, and smaller loads can be aggregated to meet the minimum.

RDRR can submit bids to day-ahead energy market but cannot submit ancillary services bids and must respond to a reliability event, RDRR should have a minimum load curtailment of 500kW and deliver reliability energy in real-time reaching full curtailment within 40 minutes and should be able to run a minimum of 1 hour and maximum of 4.

DERs have several benefits including reduced costs, avoided transmission and distribution losses, reduced emissions and reduced RPS procurements which have been discussed in several previous studies.[16] [17] [18] Participating in electricity market, can further increase the benefit to cost ratio of DERs making them more attractive to investors and ultimately help increase their penetration which will have societal benefits in terms of reduced emissions and higher reliability. To demonstrate this, a 2MW/4MWh battery energy storage previously used as the circuit battery is simulated at the distribution system and its benefit to cost ratio of the battery was determined including participation in wholesale market using EPRI StorageVet.[19] This analysis takes into account all PV production and all the loads in the two circuits and the battery is operated in a manner to optimize the benefits during the project lifetime. The cost/benefit results are shown in Figure 80. The costs include capital costs, replacements costs, and O&M costs. Note that for this analysis it is assumed that the battery is controlled by the utility and the

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[16] Razeghi, G., Gu, F., Neal, R., Samuelsen, S. A generic microgrid controller: concept, testing, and insights. Applied Energy. 2018; 229:660-671.

[17] Li, M., Zhang, X., Li, G., Jiang, C. A feasibility study of microgrids for reducing energy use and GHG emissions in an industrial application. Applied Energy. 2016;176:138-48.

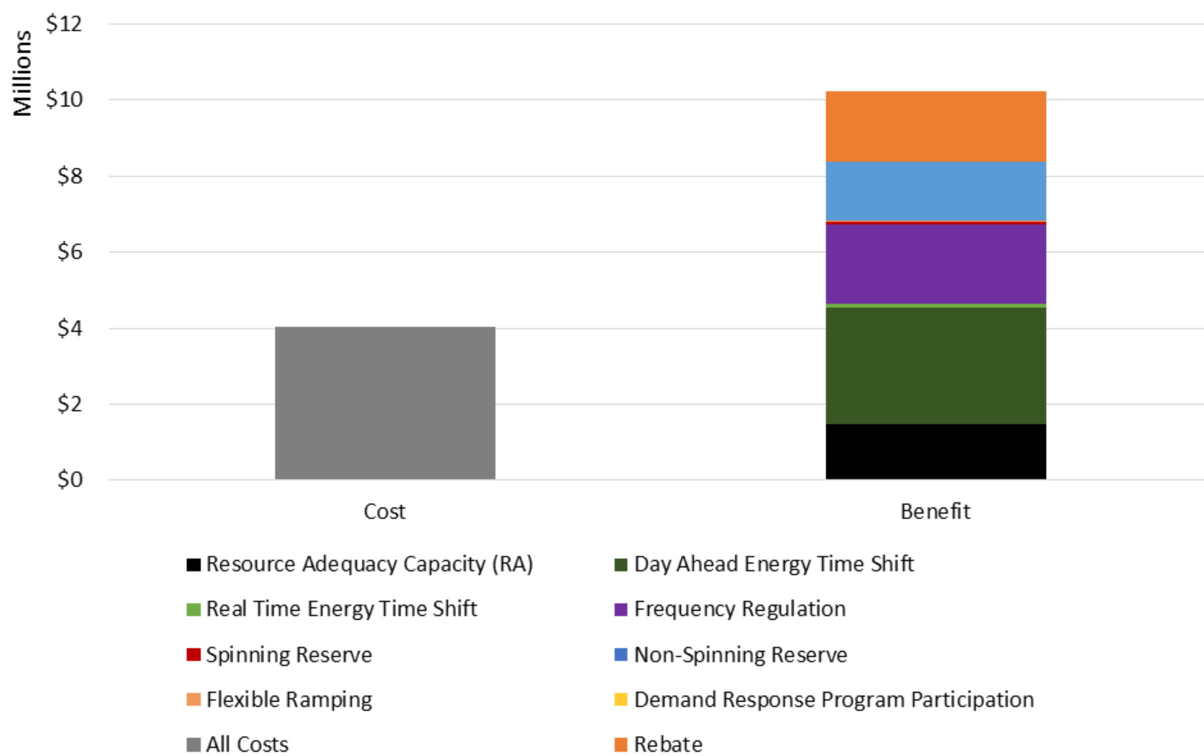
[18] Conti, S., Nicolosi, R., Rizzo, SA, Zeineldin, HH. Optimal Dispatching of Distributed Generators and Storage Systems for MV Islanded Microgrids. IEEE Transactions on Power Delivery. 2012;27:1243-51

[19] Electric Power Research Institute. https://www.storagevet.com/

customer load and PV profile are that of the total of the two circuits. This approach treats the two circuits as one single entity (similar to a microgrid). As it can be concluded from Figure 80, market participation (including day-ahead and real-time energy, various ancillary services such as non-spinning reserve and frequency regulation, and resource adequacy) increases the benefits of the circuit battery considerably.

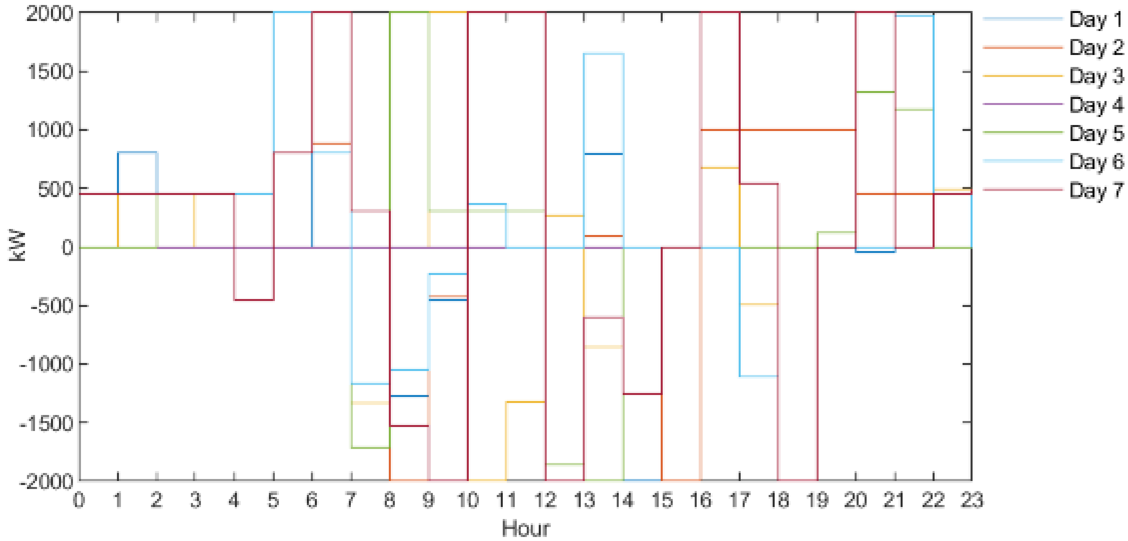
The hourly operation of the circuit battery resulting in cost/benefit shown in Figure 80, for the first seven day of August is shown in Figure 81. Each plot represents one day. Operation for the entire month of August is shown in Figure 82.

**Figure 80: Cost/Benefit Analysis for the Circuit Battery (2MW/4MWh)**



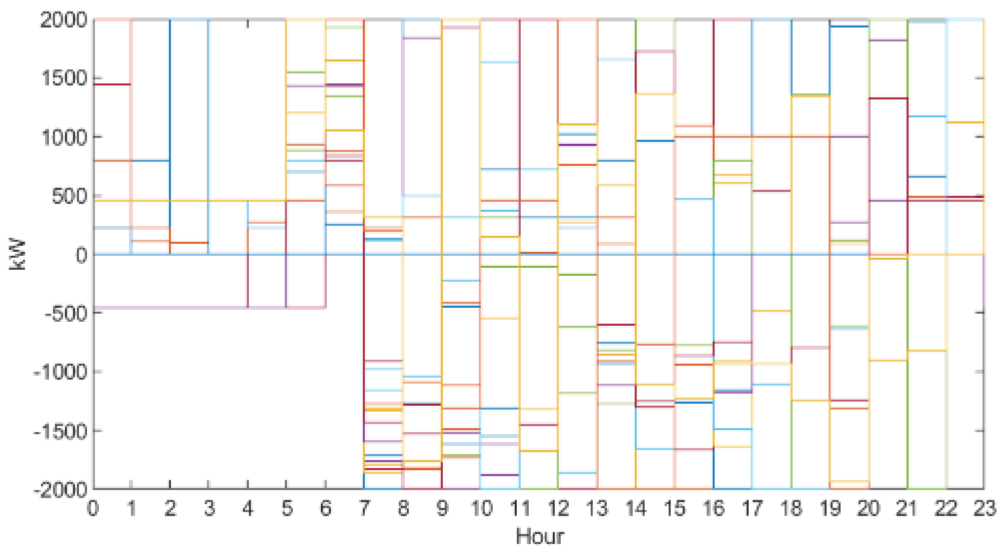

Source: UC Irvine

**Figure 81: Circuit Battery Operation for the First Week of August**




Source: UC Irvine

**Figure 82: Circuit Battery Operation for the Month of August**

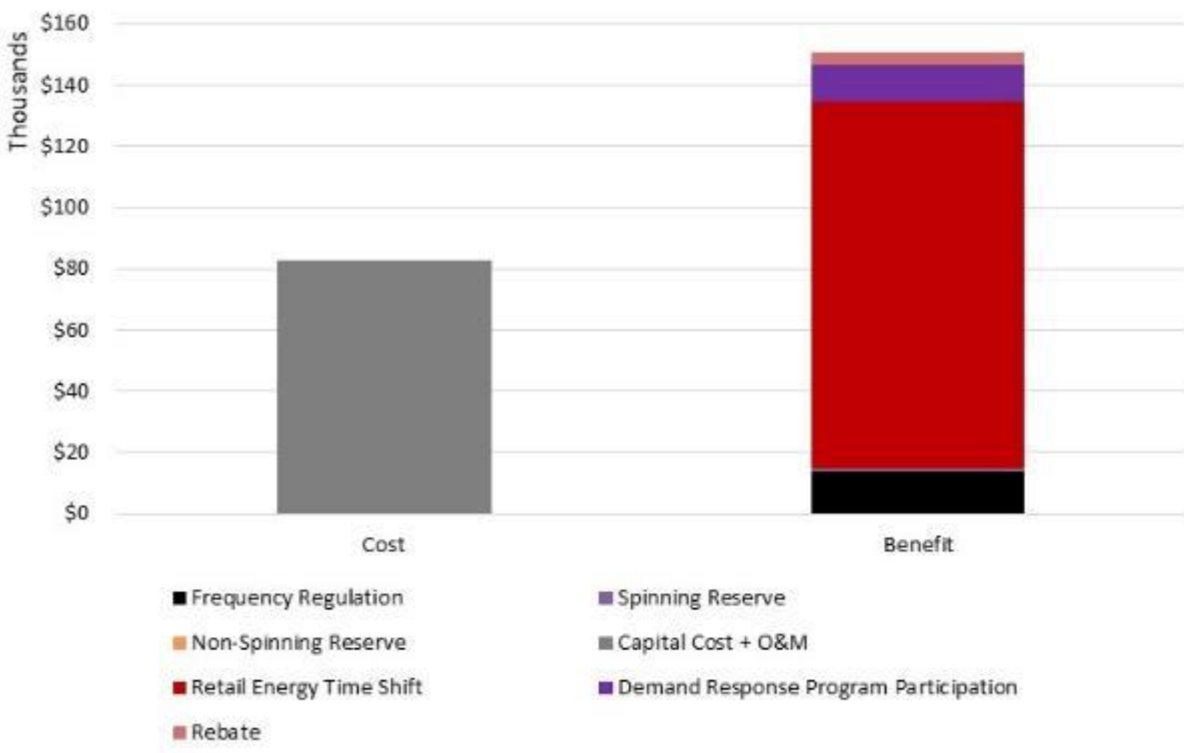



Source: UC Irvine

Note that the benefit of market participation needs to be analyzed for each DER and depends on the type and characteristics of the DER, customer load and other generation/DER behind the meter, and location of the DER (in terms of LMP, and utility rates and available programs). For example, the analysis was repeated for several ZNE homes, using the home demand and solar generation. Constraints used are similar to those used in the simulation of the circuit, with the roundtrip efficiency set as 96% and state of charge (SOC) limited between 20% and 90%. It is further assumed that the system is owned and controlled by the customer, and the battery (4kw/10kWh RESU) participates in SGIP (Self-Generation Incentive Program), and SCE demand response programs. SCE TOU tariffs and rates[20] are used for this analysis. The cost/benefit results for one of these homes is shown in Figure 83 . As it can be seen from this figure, the majority of the RESU benefits is associated with shifting load and providing demand response as well as frequency regulation. However other markets such as spinning and non-spinning reserve provide small and insignificant financial benefits to the RESU. This result is different from the circuit battery for which the market participation proved more beneficial compared to demand response and retail load-shifting. These results demonstrate that the benefits of market participation and various program for the DERs depend on size, characteristics and location of the DER. The results associated with other homes, using their load and PV profiles are similar as well.

The hourly operation of the RESU, associated with home #1 in ZNE block for 31 days of August is shown in Figure 84.

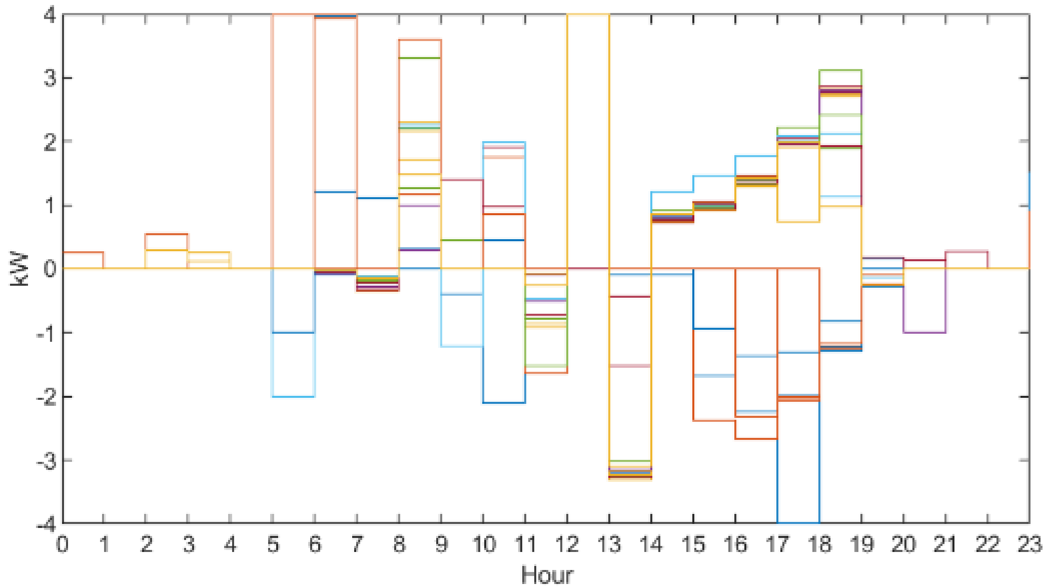
**Figure 83: Cost/Benefit Analysis Associate with a RESU (ZNE Home 1)**




Source: UC Irvine

20 Southern California Edison. Schedule TOU-D, Time of Use, Domestic. https://www1.sce.com/NR/sc3/tm2/pdf/ce360.pdf

**Figure 84: Battery Operation for the Month of August (ZNE Home 1)**




Source: UC Irvine

Cost/benefit analysis was repeated for another case in which the operation of the battery energy storage is controlled by the utility (instead of customer). In this case, there is a slight reduction in benefits of load-shifting but the rest are almost identical showing that for a small behind the meter battery energy storage, whether or not its operation is controlled by the utility has little impact on the benefit to cost ratio of the system.

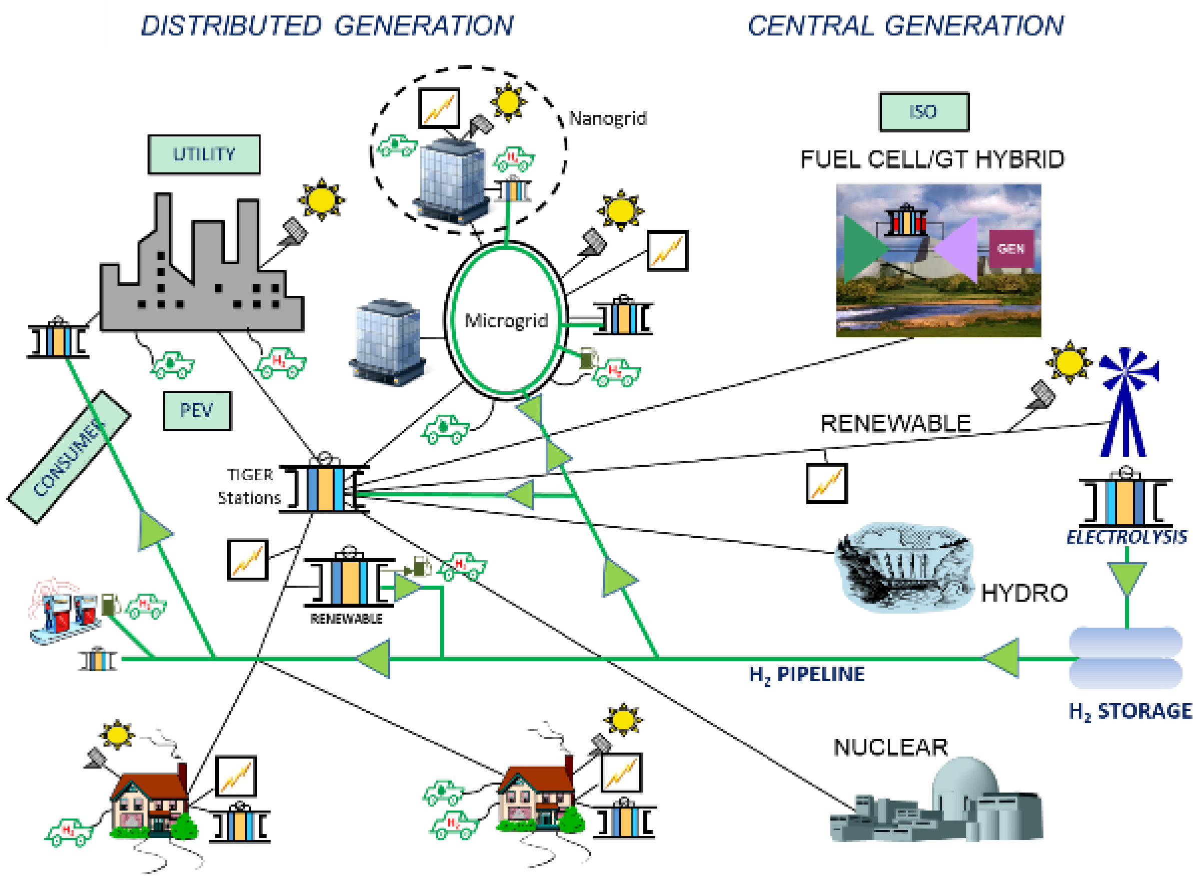
From the analysis and results shown in this section, it can be concluded that market participation can be beneficial to the DERs and increase their benefit to cost ratio. However, the extent and significance of these benefits depend on location of the DERs, size and characteristics of the resource and available programs.

## Possible Future Opportunities: Distribution/Retail Markets

So far in this chapter, a brief discussion of DER interconnection and tariffs were provided along with benefits of wholesale market participation for the DERs used in this project such as the RESU and circuit battery. Wholesale market participation contributes to and is in response to system (overall grid) needs which at times might not align with local needs of the distribution system. Furthermore, process of qualifying for CAISO market participation is complicated, time-consuming and has financial risks associated with it. As the penetration of DERs increases, the grid will experience a paradigm shift from a more centralized generation to distributed generation in which load and generation are located close to one another and some generation resources are owned by the customer and located behind the meter. Figure 85 shows the future smart grid including both centralized and distributed generation as well as microgrids and advanced technologies.

With increased DER penetration, ISO requires more distribution grid real-time visibility, forecasting of DER impacts at the transmission interface, and coordination between the ISO, utility, and DER aggregators in order to ensure a reliable and economic grid. With this added complexity, there has been renewed interest in *distribution markets* and concept of *Distribution System Operator* or *DSO,* comparable to ISO or TSO but responsible for the distribution system and serving the local needs.

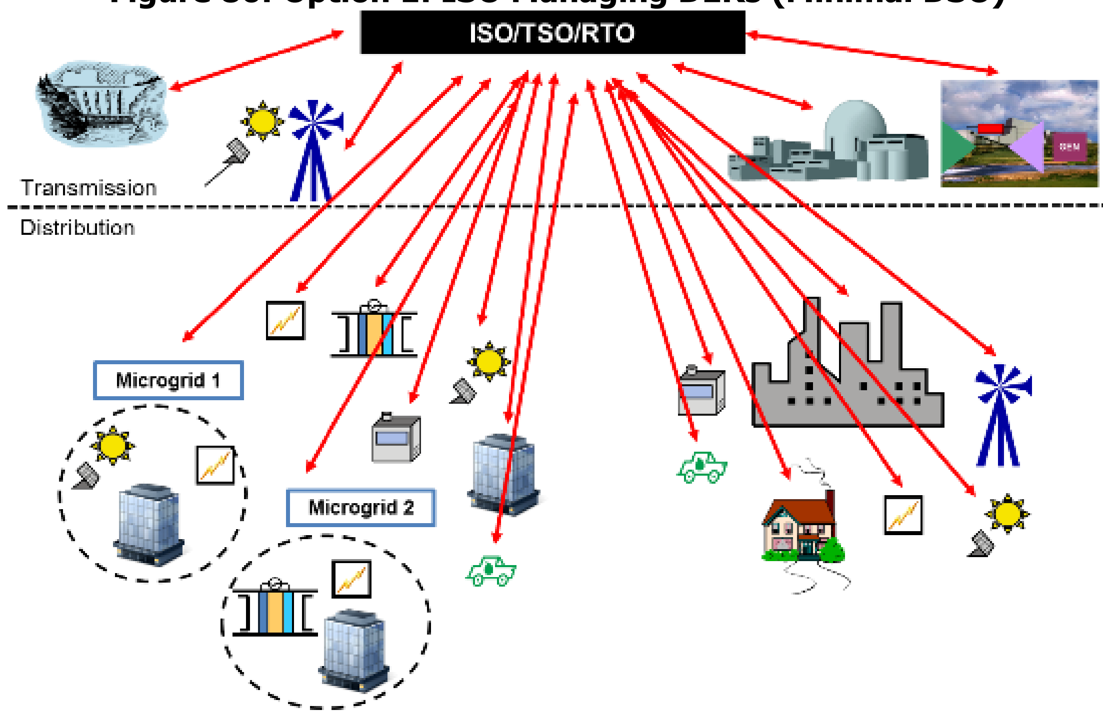
**Figure 85: Future Smart Grid**




Source: UC Irvine

To facilitate participation of DERs in the market, one option is to basically expand the ISO to include the distribution system and its resources. Note that currently the DERPs provide a net response at a P-Node and CAISO does not optimize or take into account the individual operation of DERs. To this end, ISO needs to add a full network model of the distribution system and include all the DERs in the centrally optimized ISO markets. DSO (which can be the utility) in the case act as the entity responsible for reliability of the distribution system as well as coordinating the reliability at the transmission-distribution (T-D) interface. This approach has been referred to as "Minimal DSO"[21] [22] [23]. In addition to requiring a complete model of the distribution system, this approach requires real-time monitoring of all DERs by the ISO, as well as communication and telemetry. This approach is shown in Figure 86. As it is shown in this figure, as the number of DERs increases, the operation and central optimization of ISO becomes increasingly more complicated and the network and distribution models needs to be updated, thus making this approach very complicated and not suitable for scaling to cover the entire ISO territory not be mention the computational power required to solve a mixed-integer non-linear optimization with this many variables.

**Figure 86: Option 1: ISO Managing DERs (Minimal DSO)**




Source: UC Irvine

Another option is to set up a market in the distribution system which is similar to the ISO wholesale market. This market will be run and operated by the DSO and DERs will have the option to participate in this market. In addition to T-D interface reliability, energy (or other services and products) transaction at the T-D interface will be the responsibility of the DSO as well as scheduling and dispatch of resources in the

21 De Martini, P., Kristov, L. Distribution systems in a high distributed energy resources future. 2015. https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf

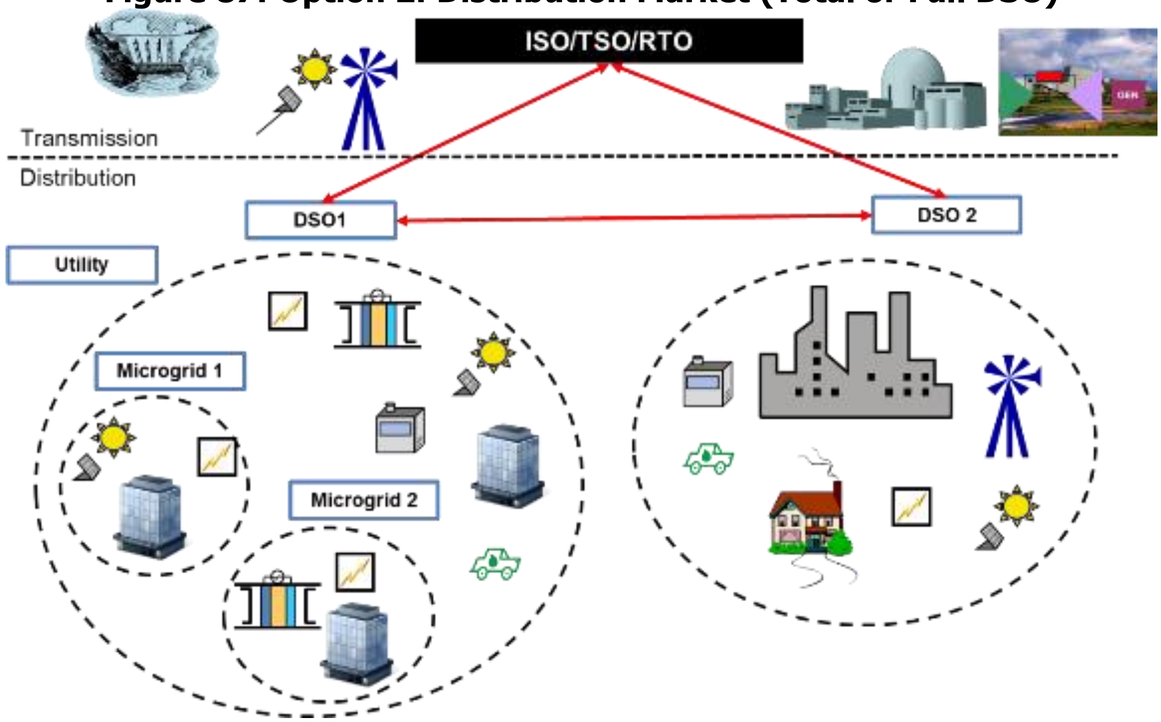
22 De Martini, P., Kristov, L. 21st Century Electric Distribution System Operations. 2014. http://resnick.caltech.edu/docs/21st.pdf

23 Kristov, L. Policy, Technology and Architecture for a 21st Century Electric System. 2017

distribution system. This approach also known as Total or Full DSO is shown in Figure 87. In this approach the only information crossing the T-D interface is the net load (+ or 1) and the marginal price of the distribution market (or the market clearing price associated with each DSO). This considerably reduces the number of variables in the ISO central optimization and result in:

- Reduced complexity
- Balancing supply and demand locally
- Serving local needs of higher reliability and increased renewable penetration
- Scalability
- Possible active and direct participation of demand (see section 0)
- Facilitating participation of microgrids and DERs (without the need for aggregation and distributed energy resources providers)

**Figure 87: Option 2: Distribution Market (Total or Full DSO)**




Source: UC Irvine

The objective of the DSO optimization will be to minimize the overall system cost similar to the ISO; however, this system is limited to the distribution system under DSO authority. This optimization is constraint also to ensure the reliability of the distribution system as well as T-D interface. This cost includes the cost associated with the DERs inside the territory of the DSO (includes production cost, and start-up cost depending on the technology), and the cost associated with import/export from/to other DSOs and the ISO. The general objective function is shown in Eq(7.1). In this equation, the first part is associated with the DER generation cost in which $N_g$ is the total number of DERs,

$C_i$ is the cost function of $i$-th DER, and $S(i,t)$ is the start-up cost of this unit at time $t$ while $P(i,t)$ is how much this DER is generating (or consuming in case of storage). The second term in Eq(7.1) is associated with transactions with other DSOs. $N_{DSO}$ is the number of DSOs that do transaction with the DSO under study, $TP_{DSO}(j,t)$ is the transaction price with $j$-th DSO at time $t$ and $Imp_{DSO}(j,t)$ is the amount of import (or export) with the $j$-th DSO. The last term in Eq(7.1) is associated with transaction with the ISO. The price of energy transactions between this DSO and the ISO is set as the locational marginal pricing ($LMP(t)$) at a P-Node corresponding to the DSO, and $Imp_{ISO}(t)$ represents the amount of import (or export) with at the T-D interface.

$$\text{Minimize}$$
$$\left\{\sum_{i=1}^{N_g}[C_i\, P(i,t) + S(i,t)]\right\} + \left\{\sum_{j=1}^{N_{DSO}}[TP_{DSO}(j,t)\; Imp_{DSO}(j,t)]\right\} + LMP(t)Imp_{ISO}(t) \tag{7.1}$$

The optimization is subject to several constraints. The first and most obvious constraint is balance of supply and demand shown in Eq(7.2). In this equation $D(t)$ represents demand within the DSO at time $t$.

$$D(t) = \left\{\sum_{i=1}^{N_g} P(i,t)\right\} + \left\{\sum_{j=1}^{N_{DSO}} Imp_{DSO}(j,t)\right\} + Imp_{ISO}(t) \tag{7.2}$$

Several constraints are associated with physical limits of the resources. These include generation limits (charge/discharge limit for energy storage), ramping up and down limits, SOC limits, and thermal unit minimum start-up time and minimum down times. Other constraints such as minimum on/off times are economic constraints. Another group of constraints are used to ensure the required ancillary services are available. These constrains associated with energy storage were previously discussed and are detailed in several previous publications[24] [25] [26].

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[24] Razeghi, G., Brouwer, J., & Samuelsen, S. A spatially and temporally resolved model of the electricity grid – Economic vs environmental dispatch. Applied Energy 2016; 178, 540–556.

[25] Razeghi, G. The Development and Evaluation of a Highly-Resolved California Electricity Market Model to Characterize the Temporal and Spatial Grid, Environmental, and Economic Impacts of Electric Vehicles. Ph.D. Dissertation. University of California, Irvine. 2013

[26] Razeghi, G., & Samuelsen, S. Impacts of plug-in electric vehicles in a balancing area. Applied Energy.2016; 183, 1142–1156

Depending on the location of the DSO, there might be limit associated with specific pollutants and emissions. This constraint is shown in Eq(7.3). In this equation, *EM(i.j)* is the emission factor for pollutant *j* of unit *i*, and *SE(i,j,t)* is the start-up emission of unit *i. REL(j)* is a specific region's limit for the same pollutant.

$$\sum_{i \in A}^{N_g} \sum_{t=1}^{N_t} \left[ EM(i,j)\big(P(i,t)\big) + SE(i,j,t) \right] \leq REL(j) \qquad (7.2)$$

Other constraints are associated with the electrical system such as the possible restriction at the T-D interface. Since the current system is designed based on central generation, it is expected that all the distribution load can be served by the ISO; however, if the upgrades to the transmission system in the future take into account the increasing DER penetration, there will be a limit at the T-D interface.

Overall this problem is a non-linear problem and taking the unit commitment approach, it is a mixed-integer non-linear problem which is difficult to solve. Moreover, for the current project, since the size of the DSO encompassing the two circuits is much smaller than the ISO territory, it is expected that the operation of the DSO in general will not have significant impact on the result of the ISO market (the *LMP* variable shown in Eq(7.1). However, as the number of DERs and DSOs grow, the ISO market prices and *LMP* will be affected by the operation of the DSOs and as a result *LMP* in Eq(7.1) is not known anymore and becomes a variable itself. This means that the ISO optimization and DSO optimization will be coupled and even more complicated to solve. In the next section, a simple approach is taken for the DSO in which the ISO prices are considered known, solar PV (and other renewables) are considered must-take resources in the market, and the behavior and benefits of the DSO market for the retail customer are assessed.

## Participation of Retail Customers (Retail Market)

The focus of the distribution market so far has been on the resources and their providing services through the DSO market. The buyer in this market can be utilities, entities representing a group of customers, or retail customers. Direct participation of retail customers is referred to as retail market. Several states already allow customers to choose the entity they want to buy electricity from and that entity (ESP) interacts directly with the wholesale market, and they pay a fee to use the infrastructure (to the utility or distribution owner). Distribution markets provide another option for the customers and that is their direct participation in the market. Benefits of community choice aggregation include increased local control over rates, possible savings for the customer, and possible increase in DER and renewable penetration. However, so far benefits to the customer have been marginal and unclear and EIA (Energy Information Administration) reports that electricity residential retail choice participation has declined since 2014 peak (from 17.2 million customers in 2014 to 16.2 million customers in

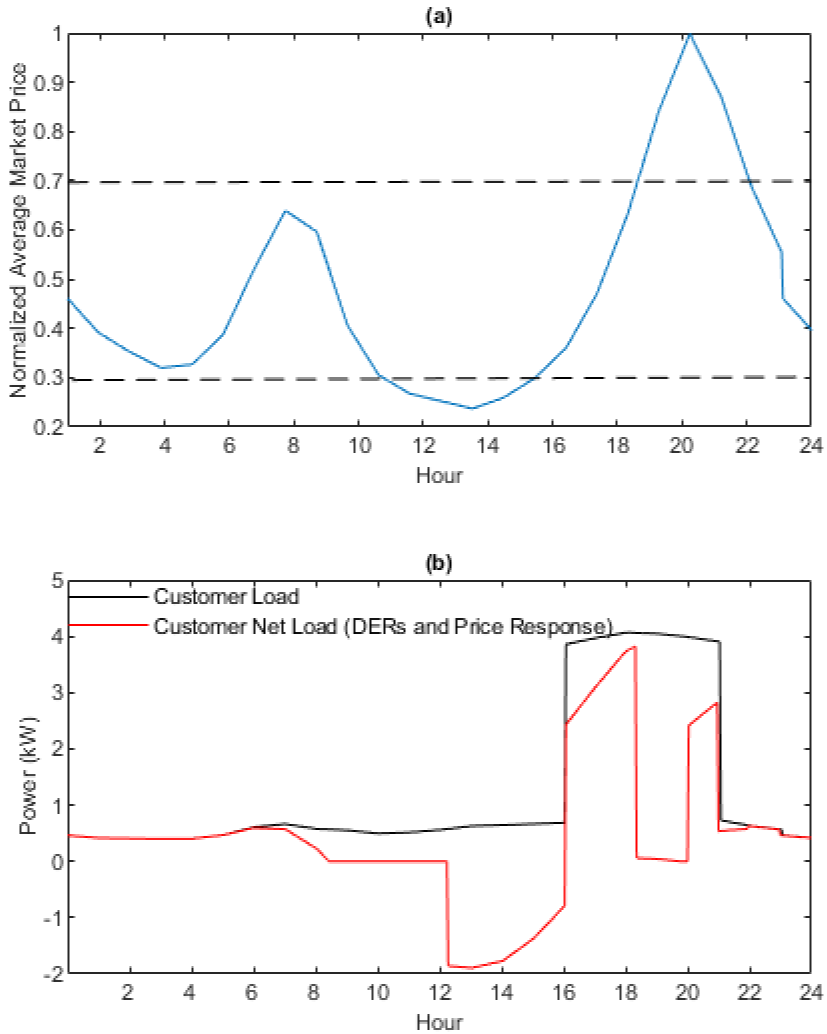
2016)[27] [28]. While the benefits to the customers are in doubt, it is widely believed that participation of retail customers in the market will result in flexibility of the demand side. This is anticipated because of the fact that the wholesale prices or distribution market prices will flow down to the retail customer and thus the customer will have visibility in the real-time prices which encourages the customer to high prices by reducing demand and overall increase the flexibility of the electricity demand. To assess this, a RESU home previously described and used in this project, is assumed to be directly involved with the market. The average market prices for the CAISO in 2017 are used for this purpose and the values are normalized in order to get an average daily price profile[29]. This price profile is shown in Figure 88a. It is assumed that for prices higher than 0.7., the customer tries to reduce its demand by first discharging the battery and second do demand response (with a maximum of 40%) if necessary to reduce its demand as much as possible. Note that a maximum demand response is used since it is expected that even with very high prices, the electricity demand will not be zero. For prices lower than 0.3, the customer chooses to use the grid power to charge the energy storage. The results for a RESU customer are shown in Figure 88b. In this figure, the original customer load is shown which includes a plug-in electric vehicle as well as the customer net load after the dispatch of DERs (both battery and solar) and response to the price signal as mentioned above which is the net load of such customer both selling and buying from a distribution market (distribution/retail market). This figure indicates that seeing the price signal results in the customer to reduce its net consumption during high price interval (from 6-10pm) by discharging the battery as well as dropping loads). Furthermore, during highest price signal, the customer discharges the battery and drops the load to a point of exporting power and selling to the market at this high price point. This figure also shows that the customer is exporting at times of low prices. This is due to the fact the customer has extra PV that will be otherwise curtailed (battery is fully charged), as a result selling it at a low price is still beneficial. Combining Figure 88a and Figure 88b, it can be calculated that without any DERs, this customer would pay an average of 465 units (note that the price signal was normalized) per day for electricity, including all the DERs and distribution market participation, the customer bill is reduced to 180 units. Therefore providing a saving of 61% for the customer in electricity bill (which translates to roughly $2500 annual savings for this particular customer). Therefore, retail market benefits both the customer and the grid (by providing demand flexibility).

[27] U.S. Energy Information Administration. 2018. https://www.eia.gov/todayinenergy/detail.php?id=37452

[28] U.S. Energy Information Administration. 2018. Annual Electric Power Industry Report

[29] U.S. Energy Information Administration. 2017. https://www.eia.gov/todayinenergy/detail.php?id=32172

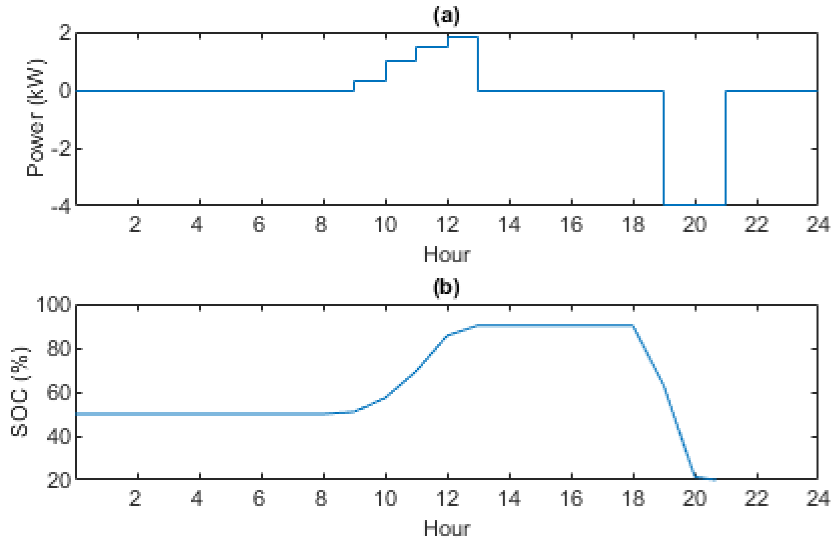
**Figure 88: (a) Price Signal, (b)Customer Net Load After Retail Market Participation (includes DERs)**




Source: UC Irvine

Battery power and state of charge (SOC) associated with this customer, are shown in Figure 89a, and Figure 89b, respectively. This figure demonstrates that the battery charges with the PV or during low-price intervals, and discharges during high-price intervals. Note that the battery only operates between SOC of 20 and 90%.

**Figure 89: Battery (a) Power, (b) SOC Associated with Price Response**




Source: UC Irvine

The results presented show that participation in the distribution/retail market has the potential to be beneficial to the end-users. However, this requires the customers to invest in DERs including PV and battery with relatively high capital costs as well a home energy management system to operate the DERs and optimize the market participation, and smart appliances capable of demand response. Note that these initial costs are not included in this saving (see section 0 for detailed cost/benefit analysis).

## Distribution Market Challenges

There are several challenges associated with setting up and running a distribution market.

- DSO Start-up and Operation Costs: The first step in developing a distribution market is assigning a DSO or starting one. The obvious and easy choice is to have the utility play the DSO role; however, issues of conflicts of interest rise since it is expected that the DSO be an independent and impartial party and utilities benefit from selling electricity to customers. Setting up a new entity to serve as the DSO can be both time-consuming and costly. FERC the average RTO requires an investment of $38-$117 million dollars and annual revenue requirement of $35-$78 million dollars[30]. It is estimated that the start-up cost associated with the CAISO was $300 million dollars[31] and the CAISO 2015 budget

[30] Federal Energy Regulatory Commission. Staff Report On Cost Ranges For The Development And Operation Of A Day One Regional Transmission Organization, Docket No. PL04-16-000. 2014. http://www.ferc.gov/EventCalendar/Files/ 20041006145934-rto-cost-report.pdf

[31] Lutzenhiser, M. Comparative Analysis of RTO/ISO Operating Costs. 2004. http://www. ppcpdx.org/ComparativeAnalysisTWO.FINAL.pdf

provides for a revenue requirement of $198.5 million showing an increase of 0.6% a year since 2007[32]. It is expected that DSOs will cost much less than RTO/ISOs but they will still require significant investment as well as rules and regulations that will govern these entities.

- Metering and Gathering Data: Since the DERs can each participate in this market, metering is required for billing and settlement purposes as well as developing and improving a full distribution system model.
- Control Equipment: For DERs including demand response and microgrids, in order to be able to be competitive in such markets, they will require sophisticated control systems capable of responding to market signals and local needs of the system.
- Tariffs and Interconnection Agreement: In this new paradigm, there needs to be a change in how the current tariffs and interconnection agreement work
- Protecting the Customer: There might still be a need for a different type of regulation in order to protect the customer from unreasonably high prices.
- Pricing: The pricing suggested previously is based on the DSO clearing price which indirectly includes the ISO price; however, there are other pricing schemes for the retail customers suggested in the literature such as static (flat or time-of use) and dynamic (real-time pricing, critical peak pricing) pricing.
- Ensure Competitiveness: This issue is related to the overall concept of deregulation and whether it actually helps reduce prices. FERC analysis showed that the RTO/ISO impact on the customer bill should be less than 0.5% and several studies have shown that deregulation might not be the reason for reduction in electricity prices. Ensuring competitiveness to the extent that results in lower prices is even a more complicated issue at a distribution level especially at the start of this new market when the benefits of market participation might not be evident to investors.
- Narrow Profit Margins: In previous sections, it was shown that DERs can benefit from ISO market participation. If the DSO market actually results in lower prices, the profit margin of the DERs will be lower than what previously showed unless the DSO introduces new products and new markets aimed at responding to local

[32] Razeghi, G., Shaffer, B., Samuelsen, S. Impact of electricity deregulation in the state of California. Energy Policy. 2017; 103: 105-115

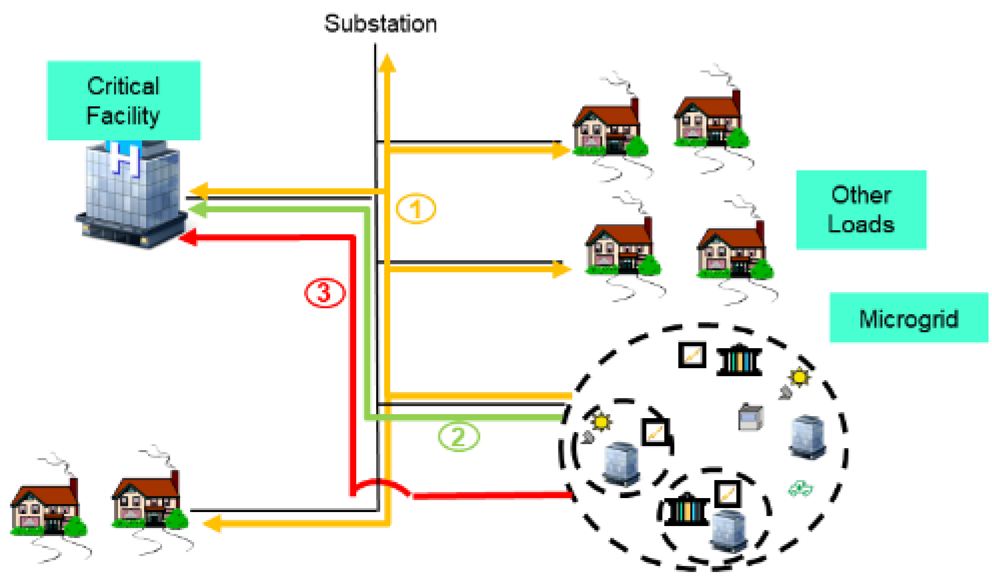
needs and improving the resiliency of the community for instance use of DERs for quick and efficient system restoration and black-start of substations[33] [34].

## Suggested Changes

In short to medium term, some changes are required to facilitate integration of DERs. These include simplifying current processes for interconnection agreements with the utility that also allow export of electricity to the grid that are more economically beneficial to the customer than existing net-metering. These changes should also cover microgrids and allow them to export and sell the extra electricity (especially renewable generation) to the utility, ISO markets, or other retail customers.

Another change that will increase the value of DERs and facilitate their integration is associated with IEEE 1547. These resources will disconnect from the grid during outages or fluctuations; however, they can be used during these occurrences to energize an entire circuit (if large enough), just serve the critical loads through opening and closing switches or through a dedicated line. These three options are shown in Figure 90. These resources can also be used to optimize and facilitate system restoration.

**Figure 90: DERs and Microgrids Used During Grid Outages**




Source: UC Irvine

[33] Xu, Y., Liu, C., Schneider, K. P., Tuffner, F. K., & Ton, D. T. Microgrids for Service Restoration to Critical Load in a Resilient Distribution System. IEEE Transactions on Smart Grid 2018; 9, 426–437.

[34] Xu, Y., Liu, C., Wang, Z., Mo, K., Schneider, K. P., Tuffner, F. K., & Ton, D. T. DGs for Service Restoration to Critical Loads in a Secondary Network. IEEE Transactions on Smart Grid. 2018; 1.

New ISO products and interconnection agreements that facilitate DER integration are also required which include the “value” of DER instead of their price/cost. This means that benefits of the DERs (direct and indirect) be included in their bid. For instance, use of DERs eliminates the 6% transmission losses and defers investments in transmission upgrades; however, these benefits to the grid do not impact the LCOE of the unit itself. Using value of the service which includes the benefits to the system (and society) further increases the penetration and integration of DERs. Cost and benefits of DERs and microgrids are summarized below.

### Costs

- Equipment Capital Costs
- Equipment Operating & Maintenance Costs
- Fuel Input Costs
- Site Preparation Costs
- Increased Market Participation Costs
- Increased Controller Costs

### Benefits

- Avoided Criteria Pollutants
- Avoided Greenhouse Gas Emissions
- PV Smoothing
- Increased Renewable Resource Integration
- Optimized DER Dispatch
- Operating Efficiencies
- Reduced Operating Costs
- Reduced Water Usage/Costs
- Peak Shaving/Load Shifting/Demand Charge Reduction
- Energy Charge Reduction
- Reduced Grid Congestion
- Deferred T&D Capacity Investment
- Provision of Ancillary Services & Voltage Support
- Islanding Capability
- Increased Reliability
- Reduced Number and Duration of Outages
- Increased Resiliency
- Reduced Cost of System Restoration after Outages

In long-term and in order to have a distribution/retail market, there needs to be new products and markets in the ISO to include participation of DSOs. There needs to be rules and regulations for the interactions between DSO and other DSOs, ISO, ESPs and retail customers, as well as new interconnection agreements between DERs and utility (which will become the distribution owner) and possible orders and rules to ensure that the DERs have non-discriminatory access to the distribution system (similar to open access rule).

# CHAPTER 7: Benefits of the Project

In this chapter, the benefits of the project for the state of California and especially IOU ratepayers are discussed. The main benefit of this project is producing a methodology and strategy that increases, through a systematic use of utility substation resources, the penetration of distributed energy resources including renewable resources and energy storage, makes full use of smart grid technologies, and implements automation and control. Several benefits of the project stem from increased penetration of distributed energy resources (especially renewable resources such as solar PV) include reduced criteria pollutants emission, reduced greenhouse gas emissions, increased grid reliability and increased energy security (due to decreased dependence on foreign oil and fossil fuels).

## Reduced Emissions

Optimal dispatch of resources through utility substation automation results in more efficient operation and ultimately in reduction of the emissions intensity of the grid. Better grid management by the deployment and application of microgrid control on distribution circuits emanating from utility substations also results in increased penetration of renewable resources and complementary technologies further reducing the emissions from the electricity sector.

Use of distributed energy resources eliminates delivery losses. Energy Information Administration (EIA) estimates that the average delivery losses (including transmission and distribution losses) are about 5% in the United States[35].For the state of California the delivery losses are estimated to be 6.58%[36]. Using distributed energy resources to replace central generation eliminates this 6.58% energy loss reducing both emissions and fossil fuel use. .

Furthermore, the electricity generated from the DERs have lower emission factors compared to the grid (due to high penetration of PV, energy storage, and low emission factors of the fuel cell). For scenarios simulated, the emission reductions compared to the base case are calculated.

In order to determine GHG emission reduction due to integration of DERs, the NREL PVWatts tool[37] is used to estimate the year around total electricity production of a grid

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35 Energy Information Administration. https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

36 California Public Utilities Commission (CPUC). System Efficiency of California's Electric Grid. 2017

37 National Renewable Energy Laboratories. PVWatts Calculator. https://pvwatts.nrel.gov/pvwatts.php

connected photovoltaic system. The calculator requires the system location and basic design parameters such as size, module type, and system losses to estimate monthly and annual electricity production of PV system using an hour by hour simulation over a period of one year. Table 12 shows the result from the PVWatts calculator for the total PV installation of 9.89MW associated with scenario 1 results.

**Table 12: Annual Electricity Production of 9.89 MW PV**

| Month | AC Energy ( kWh ) |
|---|---|
| January | 1,073,450 |
| February | 1,094,330 |
| March | 1,445,488 |
| April | 1,538,395 |
| May | 1,599,889 |
| June | 1,596,346 |
| July | 1,647,779 |
| August | 1,632,193 |
| September | 1,428,239 |
| October | 1,290,149 |
| November | 1,096,369 |
| December | 992,895 |
| Total | 16,435,522 |

Source: UC Irvine

The emission data were extracted from the Emissions & Generation Resource Integrated Database (eGRID)[38] released by the EPA. It is a comprehensive source of data on the environmental characteristics of electric power generated in the United States. From the eGRID2016, California grid average emission rates were found as shown in Table 13 and the total emissions offset by the PV installation was calculated.

**Table 13: Annual Average Emission Factors for CA (kg/MWh)**

| $NO_x$ | $SO_x$ | $CO_2$ | $CH_4$ | $N_2O$ | $CO_2$ equivalent |
|---|---|---|---|---|---|
| 0.257 | 0.024 | 239.437 | 0.015 | 0.002 | 240.356 |

Source: U.S. Environmental Protection Agency (EPA). Emissions & Generation Resource Integrated Database (eGRID) 2016

The GHG reduction associated with deployment of 9.89 MW of PV on the two circuits is equal to 4,229 $mTCO_{2eq}$ (metric Ton of $CO_2$ equivalent) annually assuming that the

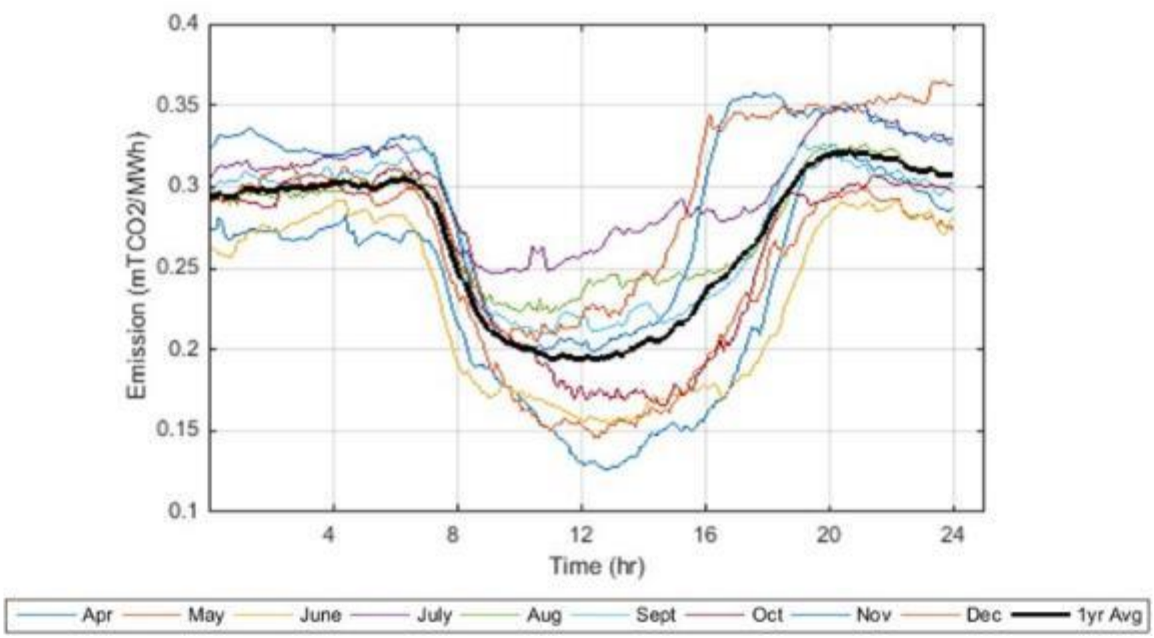
[38] U.S. Environmental Protection Agency (EPA). Emissions & Generation Resource Integrated Database (eGRID). https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid.

excess PV generation is exported to the grid for full usage and not curtailed. The transmission loss of 6.58% is also accounted in the offset emissions.

Following the same approach, annual GHG reduction from installation of 15.29 MW of PV (max RESU results) is equal to 6,537 $mTCO_{2eq}$. This only accounts for the PV installation and avoiding delivery losses, and does not take into account the impact of energy storage operation on reducing emissions. To further investigate the impact of the different energy storage units (RESU and CES), hourly emission factors of the average CA grid are used.

An hourly metric ton $CO_2$ per MWh was calculated with the demand data and emissions data from CAISO[39]. Each month and year were averaged starting April until mid-December of 2018 as shown in Figure 91. The midday drop in emissions reflects the PV deployment and electricity generation. Accounting the dynamics of emissions for 24 hours can give a more accurate and detailed emissions analysis. The 2018 average day hourly emission factor is shown in black in Figure 91. This profile is used to estimate the emissions for the 24 hour simulation of the RESU max case and the CES max case in order to assess the impact of energy storage on shifting the load from high to low emission intervals.

**Figure 91: Average GHG Emission Factor for 2018**

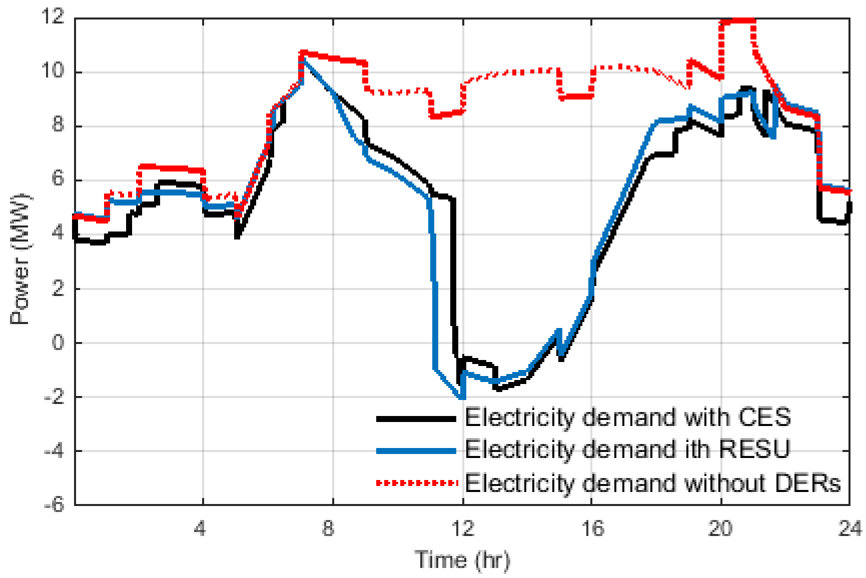



Source: UC Irvine

[39] California Independent System Operator (CAISO). http://www.caiso.com/TodaysOutlook/Pages/emissions.aspx

The electricity profile without DER, the red profile in Figure 92, is used to determine the GHG emissions of the baseline using average hourly emission factors shown in Figure 91. The electricity demand profiles with RESUs and CESs from Figure 92 is used to determine the emissions for two different storage cases. The transmission loss of 6.58% was added to the calculation to account for delivery loss.

**Figure 92: Electricity Demand**




Source: UC Irvine

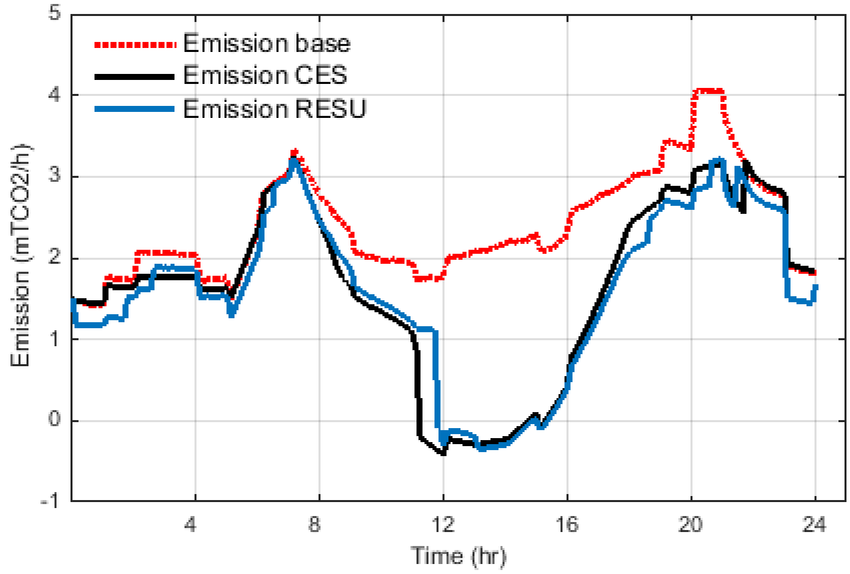
The Baseline, RESU case and CES case $CO_{2eq}$ emissions are as listed in Table 14. Given that the RESU case has more storage (both in terms of power and energy), RESU case resulted in less $CO_{2eq}$ emissions compared to the CES case. A maximum of 19.7 $mTCO_2$ per day is offset (associated with RESU scenario) and this results in 7,712 $mTCO_2$ reduction per year including the transmission loss of 6.58%. This results in a **34 % reduction** in GHG emissions from these two circuits for the RESU case and **32% reduction** for the CES case. Figure 93 shows the different GHG emission profiles for an average day for different cases. There is significant reduction in emissions during midday due to PV electricity generation and the highest emission points during the evening hours are reduced due to the energy storage operation shifting the loads to intervals with lower emission intensity.

**Table 14: Annual GHG Emission**

| Baseline $CO_{2eq}$ Emissions | RESU case $CO_{2eq}$ Emissions | CES case $CO_{2eq}$ Emissions |
|---|---|---|
| 20,971 $mTCO_2$ | 13,766 $mTCO_2$ | 14,237 $mTCO_2$ |

Source: UC Irvine

**Figure 93: Average Daily GHG Emission Profile**




Source: UC Irvine

This analysis further shows the impact and importance of integrating energy storage with renewable resources to further decrease GHG emissions.

## Improved Reliability

The reduction in outage duration due to availability of DERs and the controller is calculated from the results of the circuit-independent test cases. This is then used to calculate a new SAIDI (System Average Interruption Duration Index), this new SAIDI number is then compared to the base case SAIDI numbers shown in Table 15 for SCE territory.

**Table 15: SCE Total System Reliability Indices**

| Year | SAIDI | SAIFI | MAIFI | CAIDI |
|---|---|---|---|---|
| 2017 | 139.73 | 1.19 | 1.84 | 117.19 |
| 10 Year Avg(2007-2017) | 130.99 | 1.00 | 1.52 | 130.71 |

**SAIDI = System Average Interruption Duration Index; SAIFI = System Average Interruption Frequency Index; MAIFI = Momentary Average Interruption Frequency Index; CAIDI = Customer Average Interruption Duration Index**

Source: Southern California Edison. Annual System Reliability Report, Prepared for California Energy Commission. 2017. https://www.sce.com/sites/default/files/inline-files/SCE_2017_Annual_Reliability_Report.pdf

Results of the two emergency scenarios simulated are summarized in Table 16. The total unserved load was calculated using the original base case demand and the new demand after load shedding necessary to balance demand and supply during a grid outage. 44% and 43% of the total load was dropped (unserved load) in the CES and RESU cases, respectively. The loads that were dropped, experience the same outage duration as the rest of grid while the rest of the load which was served by the DERs do not experience any interruption. Thus, 60% of the load was not subject to an outage during the circuit independent operation simulations.

**Table 16: 24 Hours Emergency Operation Result**

| Scenario | Demand (MWh) | New Demand (MWh) | Unserved Load (%) | New SAIDI | New SAIFI |
|---|---|---|---|---|---|
| CES | 210.59 | 117 | 44.44 | 62.09 | 0.5288 |
| RESU | 210.59 | 120.6 | 42.73 | 59.71 | 0.5085 |

Source: UC Irvine

The new SAIDI and SAIFI for the two circuits were calculated using Eq (8.1) and Eq (8.2):

$$SAIDI_{A\&B} = SAIDI_{2017} \times OP_{A\&B} \tag{8.1}$$

$$SAIFI_{A\&B} = SAIFI_{2017} \times OP_{A\&B} \tag{8.2}$$

In these equations, $OP_{A\&B}$is the outage percentage outcome from the 24 hour simulations. The total interruption duration will reduce by $OP_{A\&B}$ and the total interruption frequency will also reduce by $OP_{A\&B}$. The new SAIDI and SAIFI show an improvement of over 60% and with a more sophisticated energy management system per home, it is possible to achieve higher improvements.

The Interruption Cost Estimate (ICE)[40] calculator tool is utilized to estimate the economic benefit of reliability improvement resulted from integration of DERs. The ICE calculator is a tool developed for those that are interested in estimating interruption costs and benefits associated with reliability improvements. First the interruption cost using the 2017 average SAIDI and SAIFI was calculated assuming that the customers are all residential. Then, the interruption cost using the improved SAIDI and SAIFI are calculated and compared to the original value. Table 17 shows the results of the calculation and the economic benefit drawn from the reliability improvement per event associated with the customers located in the system under study. The interruption cost is almost halved due to reliability improvement achieved due to deployment of DERs including the fuel cell.

[40] Lawrence Berkeley National Laboratory. Interruption Cost Estimate Calculator. https://eaei.lbl.gov/tool/interruption-cost-estimate-calculator

**Table 17: Interruption Cost Estimate**

| Item | Cost |
|---|---|
| Old Index Interruption Cost | $30,846.30 |
| New Index Interruption Cost | $13,180.93 |
| Outage Cost Reduction | $17,665.37 |

Source: UC Irvine

## Lower Costs

An EPRI report[41] has shown that the benefits of smart grid technologies outweigh the required costs with the cost to benefit ratio of 2.8 to 6 for the entire U.S. The main functionality of the controller is dispatch the resources available to meet the demand. For business as usual operations which is the majority of the time, the controller optimizes dispatch of the available resources on the distribution system. This optimization by definition should result in lower operation costs and a low cost option for dealing with the intermittencies introduced in the grid by renewable resources. This is in the context of meeting energy and environmental goals, thus the results are not compared the least cost generation (such as coal or nuclear).

Modeling and analysis of distribution circuits prior to DER deployment, will also result in developing a robust strategy on locating the DER across the distribution network and as a result the assets will neither be stranded nor underutilized. As previously mentioned, achieving 5% improvement in operation is achievable through optimized dispatch, which can lower the system cost. If implemented throughout the state, the efficiency of the grid operation will increase an average of 5% saving almost 13 TWh annually[42].

Furthermore, depending solely on distributed resources will eliminate transmission and distribution losses saving another 15.5 TWh annually for the entire state of California.

As previously mentioned, integration of DERs as described in this project result in reliability improvement. Using the new calculated SAIDI and SAIFI (Table 16) as inputs to the ICE calculator demonstrate that this reliability improvement has a benefit of $4.5-$5.5 per residential customer and has the potential to save $67M-$82M for SCE customers in total.

Reduced restoration costs is another benefit of smart grid equipped with controller. In the case of an outage, the controller can help bring the assets up in the most efficient manner while contributing to overall grid restoration.

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[41] http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001022519

[42] U.S. Department of Energy. State of California Energy Sector Risk Profile. http://energy.gov/sites/prod/files/2015/05/f22/CA-Energy%20Sector%20Risk%20Profile.pdf

## Other Benefits

In this section, other benefits of this project are described.

### Reduced Fossil Fuel Usage

With the integration of DERs, up to 28.5GWh of energy is generated annually in the two circuits. This implies that less electricity is required from centralized generating units. California reported state average heat rate for natural gas-fired generating units is 8513 Btu/kWh[43]. Using this heat rate and accounting for delivery losses, integration of DERs in the system under study in this project will result in a reduction of 2.5E11 Btu of natural usage annually.

### Reduced Energy Demand

Results of the project have shown that integration of DERs including distributed generation, energy storage, energy efficiency, and demand response, all reduce the net load seen at the substation and reduce the overall electricity demand. This is in addition of the 6% reduction in load due to avoiding delivery losses. The extent of this reduction depends on the technology and was described in detail in result of each scenario simulation in Chapter 6.

### Increased Safety

Enhancing automation and control capabilities of the substation, and communication between the controller and DERs allows for quick resolution and response to faults, outages, and other issues which results in increased safety for both customers and utility personnel/workers.

Controlling load further allows for ensuring that the critical loads are being served in case of an emergency.

### Energy Security

Use of renewable energy resources, energy storage, and demand management, reduce the need for conventional generation and thus reduce the dependence on foreign oil and gas.

### Enhanced Resiliency

Use of DERs, especially if they are allowed to operate during grid outages, can help improve the resiliency of the grid. These resources can help achieve an optimized and quick system restoration by energizing part of the grid and help black-start utility assets. As previously mentioned, used of DERs and microgrids in system restoration has been covered in multiple studies.

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[43] Nyberg, M. Thermal Efficiency of Natural Gas-Fired Generation in California: 2017 Update. 2018.California Energy Commission CEC-200-2018-001

## Reduced RPS Procurement

Implementation of demand response, energy efficiency measures, and energy storage help reduce the overall net demand or peak net demand and thus reducing the RPS procurement which is based on demand which can further lower prices. This will result in reduced purchases and procurement of renewable generation above market prices solely to meet RPS goals.

## Avoided Transmission Upgrade Costs

Retail electricity prices include generation, transmission and distribution costs. Between 59% and 67% of the price is associated with generation of electricity[44] and the remaining 41% to 33% is associated with transmission and distribution costs. Furthermore, transmission costs are projected to increase 1.2% annually between 2013 and 2040[44] (compared to 0.6% associated with distribution costs).

Due to increased integration of renewables and the necessity to increase the reliability and resiliency of the electric grid, utilities continue to increase spending on transmission. In 2016, total transmission expenditures by utilities included in the FERC data reached $35 billion, with investment in transmission infrastructure making up 61% of that total[45]. With increased penetration and use of DERs, the net load is reduced and thus the use and stress on the transmission system will be reduced which results in less frequent upgrades to the transmission system (or at least defer the investment).

[44] U.S. Energy Information Administration. Annual Energy Outlook 2015 with projections to 2040. 2015. https://www.eia.gov/outlooks/aeo/pdf/0383(2015).pdf

[45] U.S. Energy Information Administration. Federal Energy Regulatory Commission Financial Reports

# CHAPTER 8: Conclusions

In this project, the GMC software specifications, established under a U.S. Department of Energy program, were used to develop a controller which was simulated on two 12kV distribution circuits at a Southern California Edison (SCE) substation using the OPAL-RT simulation platform. The two distribution circuits were previously part of the DOE Irvine Smart Grid Demonstration (ISGD) project led by SCE in collaboration with APEP as the research partner and project host. The data collected from the ISGD project were used to validate and inform the models developed.

Developed models of the distribution circuits and the controller were used to simulate future viable scenarios in order to assess the impact of high PV penetration, energy storage, electric vehicles, and demand response on the operation of the distribution system and improving reliability. Furthermore, the viability of a distribution/retail electricity market was assessed and the fundamentals of such markets introduced.

## Major Findings

- Higher DER (including PV) penetration can be achieved with substation control and automation. Results of the simulations demonstrated that using the controller to manage the operation of DERs in distribution circuits in an optimized manner increases the PV hosting capacity of the distribution system without any upgrade. Addition of energy storage units and optimizing their operation can further increase PV penetration in the distribution system as was demonstrated in the RESU and CES cases.
- CES is a more economic approach for achieving high PV penetration and GHG reduction that residential storage. RESU and CES cases simulated and assessed in this project, resulted in similar PV penetration (37.5% and 35.4%, respectively). However, using CES units, this PV penetration was achieved with less battery energy storage deployed both in terms of power and energy capacity, and this represents a more economic approach since battery energy storage is capital intensive. The RESU case includes more energy storage and has slightly higher PV penetration, it results in more GHG reduction (34% versus 32% for the CES). However, RESU cases result in 355 mTCO2eq reduction per MWh of installed energy storage, while CES cases result in 660 mTCO2eq reduction per MWh of installed energy storage demonstrating that CES approach is a superior approach in terms of GHG reduction (and cost).
- DERs can be used to serve the needs of the larger grid. Although DERs mainly serve the local needs of the distribution system, they can be used to serve the needs of the larger grid, and help alleviate the duck curve in the state of

California particularly. The results of the simulations showed that a large battery deployed at the distribution substation helps reduce the depth of the duck curve by curbing PV export to the grid. Demand response, on the hand, helps the duck curve by reducing the demand later in the afternoon and reducing the need for high ramping rates during these times.

- Fuel cell deployment at the substation improves reliability of the system. As demonstrated by the results of the simulations, having a source of firm power at the substation helps better manage supply and demand, and reduce unserved load during grid outages. This results in significant improvement of SAIDI and SAIFI of the system.
- DER market participation is beneficial to the grid as well as DER owner/aggregator. Cost/benefit analysis performed in this project showed that overall market participation increases the benefit to cost ratio of DERs making them more attractive to investors. The extent of the benefits and most lucrative markets for DERs depends on the size of the resource, its location, and its ownership. For example, for RESUs that are behind the meter and owned by a residential customer, the majority of DER benefits were associated with retail load-shifting and frequency regulation. For the circuit battery, however, which is much larger than a RESU and it is on the utility side, the benefits were associated with wholesale day-ahead market participation, non-spinning reserve, as well as frequency regulation. Both of these resources were able to serve the grid needs since they were cleared and used various wholesale markets.
- Participation of retail customers in distribution electricity markets can benefit them financially. By directly participating in a distribution market, retail customers will see the real-time electricity market prices and will be able to respond to such prices accordingly to reduce their overall energy bill. Results of the simulation demonstrated that this distribution/retail market can indeed help reduce the electricity bill of retail customers. Furthermore, with real-time flowing down to the retail customer, the flexibility of electricity demand is increased providing another benefit to the overall grid.

## Recommendations and Future Work

- Use of distribution circuits as microgrids should be further investigated. In this project, although emergency cases were studied, they were focused on balancing supply and demand without any electricity import from the grid. Transition to an islanded mode operation and resynchronization should be further studied.
- Use of fuel cells in system restoration and recovery can be further studied which requires a detailed analysis of fuel cell operation in grid-forming.

- Standardize, simplify, and streamline the process for interconnection agreements, and allow export of electricity to the grid that is more economically beneficial to the customer than allowed by existing net-metering rules.
- Allow DERs to export and sell the electricity to the utility, ISO markets, or retail customers.
- Rethink anti-islanding requirements and allow for intentional islands.
- Establish ISO products that are specific to DERs and microgrids enabling DERs with direct and indirect benefits included in the bid.
- Legislation is required in order to establish competitive distribution/retail markets which requires more research on the impact of such markets in long term on prices.

# LIST OF ACRONYMS

| Term | Definition |
|---|---|
| APEP | Advanced Power and Energy Program |
| AS | Ancillary Services |
| BA | Balancing Authority |
| BC | Breaker Controller |
| CAISO | California Independent System Operator |
| CCA | Community Choice Aggregation |
| CES | Community Energy Storage. This is a battery energy storage units deployed close to the transformer and serving all the customers served by that particular transformer |
| DAM | Day-Ahead Market |
| DER | Distributed Energy Resource |
| DERP | Distributed Energy Resource Provider |
| DNU | Delivery Network Upgrade |
| DR | Demand Response |
| DSO | Distribution System Operator |
| eGRID | Emissions & Generation Resource Integrated Database |
| EMS | Energy Management System |
| EMT | Electromagnetic Transient |
| EPIC (Electric Program Investment Charge) | The Electric Program Investment Charge, created by the California Public Utilities Commission in December 2011, supports investments in clean energy technologies that benefit electricity ratepayers of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. |
| EVSE | Electric Vehicle Service Equipment |
| FERC | Federal Energy Regulatory Commission |
| GC | Generation Controller |
| GHG | Greenhouse Gas |
| GIA | Generator Interconnection Agreement |

| Term | Definition |
|---|---|
| GIDAP | Generator Interconnection and Deliverability Allocation Procedure |
| GIP | Generator Interconnection Procedure |
| GMC | Generic Microgrid Controller. |
| HIL | Hardware-in-the-Loop |
| IEEE 2030.7 | IEEE standard for microgrid controller development |
| IC | Interconnection Customer |
| IOU | Investor-Owned Utility |
| IR | Interconnection Request |
| IS | Interconnection Service |
| ISGD | Irvine Smart Grid Demonstration. |
| ISO | Independent System Operator |
| LC | Load Controller |
| LCR | Local Capacity Requirement |
| LMP | Locational Marginal Price |
| LSE | Load Serving Entity |
| MCP | Market Clearing Price |
| Microgrid | A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode.” |
| MILP | Mixed Integer Linear Programming |
| MMC | Master Microgrid Controller |
| MRTU | Market Redesign and Technology Upgrade |
| NEM | Net Energy Metering |
| Nested Microgrid | Interconnection one or more nanogrids to a microgrid representing themselves as a single controllable entity to the microgrid |
| NGR | Non-Generating Resource |
| PAFC | Phosphoric Acid Fuel Cell |

| Term | Definition |
|---|---|
| PDR | Proxy Demand Resource |
| PEV | Plug-in Electric Vehicle |
| PNode | Price Node |
| POI | Point of Interconnection |
| PV | Photovoltaic |
| RA | Resource Adequacy |
| RESU | Residential Energy Storage Unit. This system refers to a PV/battery combination on the same inverter deployed on the customer side of the meter |
| RPS | Renewable Portfolio Standard |
| RTM | Real-Time Market |
| RTO | Regional Transmission Operator |
| RTUC | Real-Time Unit Commitment |
| RUC | Residual Unit Commitment |
| SAIDI | System Average Interruption Duration Index which is commonly used as a reliability indicator by electric power utilities. SAIDI is the average outage duration for each customer served |
| SAIFI | System Average Interruption Frequency Index is the average number of sustained interruptions per consumer during the year. It is the ratio of the annual number of interruptions to the number of consumers. |
| SC | Storage Controller/ Scheduling Coordinator |
| SCE | Southern California Edison. One of three Investor Owned Utilities in the state of California |
| SCUC | Security Constraint Unit Commitment |
| SGIP | Self-Generation Incentive Program |
| Smart grid | Smart grid is the thoughtful integration of intelligent technologies and innovative services that produce a more efficient, sustainable, economic, and secure electrical supply for California communities. |
| SOC | State of Charge |
| TEV | Testing, Evaluation, and Verification |

| Term | Definition |
|---|---|
| TOT | Transmission Owner’s Tariff |
| TOU | Time of Use |
| TP | Transmission Plan |
| TPP | Transmission Planning Process |
| TSO | Transmission System Operator |
| UCI | University of California, Irvine |
| UCIMG | University of California, Irvine Microgrid |
| VNM | Virtual Net Metering |
| WDAT | Wholesale Distribution Access Tariff |
| ZNE | Nero Net Energy |

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# APPENDIX A:
# Test Case Templates

This appendix provides the test case templates.

## Template A-1: Scenario (test case) template

| TEST CASE SPECIFICATION | | TP#:<br>Name: |
|---|---|---|
| **Feature to be Tested** | **Group:** | **Purpose/Comments** |
| | | Brief Description of the Scenario |
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| | | |
| | | |
| | | |
| | | Identifying specific GMC function |
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| | | Identifying Task 3 objectives met by this scenario |
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| TEST PROCEDURE SPECIFICATION | TP#: |
|---|---|
| | Name: |

| |
|---|
| Purpose |
| |
| **Procedure steps** |
| Log |
| |
| **Setu p** |
| Identifying test condition, operating condition,<br>and<br>parameters that are monitored |
| |
| **Start** |
| Step by step test procedure,<br>and<br>expected results |
| |
| **Metrics** |
| |
| |
| **After the test** |
| Required data post-processing<br>Identify and explain deviations from expected results |
| **Success criteria** |
| Specific conditions that should be met for the test to be deemed successful |

## Template A-2: High PV Scenarios

| TEST CASE SPECIFICATION | | **TP#:** A<br>**Name:** High PV Penetration |
|---|---|---|
| **Feature to be Tested** | **Group: A** | **Purpose/Comments** |
| • Load Flow Analysis<br>• Economic Dispatch | Simulating the dispatch function on the two modeled circuits starting from the base case PV penetration to 100% | Dispatch energy and resources (including DER and imports from the utility) to achieve minimum cost while connected to the grid |
| | | Dispatch functionality of the GMC is tested to achieve increased reliability, efficiency and reduced emissions. |
| | | • The various technologies to be added as DER to the circuits under study- Solar PV<br>• The various smart grid technologies to further enhance controllability of the assets-Controller at the substation<br>• The maximum DER/renewable penetration that the circuits can handle- Will be established in these tests<br>• The impacts of DER on the distribution circuit if the maximum penetration is surpassed- will be established in these tests<br>• Viable future scenarios to be further assessed using modeling- the viability of these scenarios will be determined both by the tests and post-processing of the results |
| ☐ **Continued** | | |

| TEST PROCEDURE SPECIFICATION | **TP#:** A<br>**Name:** High PV Penetration |
|---|---|

**Purpose** Dispatch available resources to meet the demand of the circuit at minimum costs and at higher PV penetrations

**Procedure steps**

Log

**Setup**

(1) Select operating condition (electricity load, time of year to determine PV availability)
(2) The circuits are connected to the grid
(3) The GMC is simulated at the substation in OPAL-RT
(4) All node voltages, currents, and frequencies;; load and source real and reactive powers; protection device status are recorded

**Start**

1) Start with Base Case PV penetration as previously described
2) Initialize the system with the controller simulated in OPAL-RT
3) Define the rate schedule for electricity not generated by DER (SCE rate)
4) Define the cost of generation (or LCOE) associated with PV
5) The controller determines how to respond to the current load and dispatch resources
6) Verify that the resources respond to the signal and power is dispatched
7) Tabulate the results, and costs
8) Increase the PV penetration by 10% and repeat the steps 2 through 8
9) Repeat the test for different initial and operating conditions

•

**Metrics**

1) Cost of generation ($/kWh)
2) (Maximum Transient Voltage – Nominal Voltage)/ Nominal Voltage

**After the test**

1) Determine the maximum PV penetration achievable for the system ($PV_{MAX,A}$)
2) Determine the impacts on the system when the PV penetration surpasses the threshold established
3) Calculate the emissions and compare to the Base Case and the CA grid
4) Determine if the maximum PV penetration is physically feasible to install. After establishing the capacity of the PV, it will be determined it there is sufficient roof space and other open spaces on the circuits to install this much PV

☐ **Continued**

5) Verify that the cost is indeed the mimum cost (verify that the results is not a local optimum by repeating the test as suggested in step 9 with different initial conditions)

**Success criteria**

1) The electricity demand is met
2) Most economic condition is met
3) The voltage at the PCC (for the purpose of this project, it is where the circuits connects to the grid at the substation) remains in the acceptable range

## Template A-3: Energy Storage Scenarios, RESU

| TEST CASE SPECIFICATION | | TP#: B-1<br>Name: Energy Storage, RESU |
|---|---|---|
| **Feature to be Tested** | **Group: B** | **Purpose/Comments** |
| • Load Flow Analysis<br>• Economic Dispatch | Simulating the dispatch function on the two modeled circuits starting from the maximum PV and RESU deployed behind the meter for every customer | Dispatch energy and resources (including DER and imports from the utility) to achieve minimum cost while connected to the grid |
| | | |
| | | Dispatch functionality of the GMC is tested to achieve increased reliability, efficiency and reduced emissions. |
| | | |
| | | • The various technologies to be added as DER to the circuits under study- Solar PV and battery energy storage<br>• The various smart grid technologies to further enhance controllability of the assets-Controller at the substation, energy storage units capable of communicating with a central controller<br>• The maximum DER/renewable penetration that the circuits can handle- Will be established in these tests<br>• The impacts of DER on the distribution circuit if the maximum penetration is surpassed- will be established in these tests<br>• Viable future scenarios to be further assessed using modeling- the viability of these scenarios will be determined both by the tests and post-processing of the results |
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| ☐ **Continued** | | |

| **TEST PROCEDURE SPECIFICATION** | **TP#:** B<br>**Name:** Energy Storage, RESU |
|---|---|

**Purpose** Dispatch available resources to meet the demand of the circuit at minimum costs with maximum PV penetration and RESUs deployed across the circuits

**Procedure steps**

Log

**Setup**

(1) Select operating condition (electricity load, time of year to determine PV availability)
(2) A RESU is modeled for every customer.
(3) Maximum PV determined in previous simulations (PV) exist on the circuit ($PV_{MAX,A}$)
(4) Select initial condition (SOC of the battery energy storage at the beginning of the simulation)
(5) The circuits are connected to the grid
(6) The GMC is simulated at the substation in OPAL-RT
(7) All node voltages, currents, and frequencies;; load and source real and reactive powers; protection device status are recorded

**Start**

1) Initialize the system with the controller simulated in OPAL-RT
2) Define the rate schedule for electricity not generated by DER (SCE rate)
3) Define the roundtrip efficiency of the RESU
4) The controller determines how to respond to the current load and dispatch resources and determines the appropriate mode of operation for the RESUs
5) Verify that the resources respond to the signal and power is dispatched, and the RESUs are in the correct mode
6) Tabulate the results, and costs
7) Increase the PV penetration by 5% and repeat the steps 1 through 7
8) Repeat the test for different initial and operating conditions

   •

**Metrics**

1) Cost of generation ($/kWh)
2) (Maximum Transient Voltage – Nominal Voltage)/ Nominal Voltage

☐ **Continued**

| After the test |
|---|
| 1) Determine the maximum PV penetration achievable for the system with the addition of energy storage ($PV_{MAX,B1}$)<br>2) Determine the impacts on the system when the PV penetration surpasses the threshold established and compare the constraints to Group A<br>3) Calculate the emissions and compare to the Base Case and the CA grid<br>4) Determine if the new maximum PV penetration is physically feasible to install. After establishing the capacity of the PV, it will be determined it there is sufficient roof space and other open spaces on the circuits to install this much PV<br>5) Verify that the cost is indeed the mimum cost (verify that the results is not a local optimum by repeating the test as suggested in step 8 with different initial conditions) |
| **Success criteria**<br>1) The electricity demand is met<br>2) Most economic condition is met<br>3) The voltage at the PCC (for the purpose of this project, it is where the circuits connects to the grid at the substation) remains in the acceptable range |

## Template A-4: Energy Storage Scenarios, CES

| TEST CASE SPECIFICATION | | TP#: B-2<br>Name: Energy Storage, CES |
|---|---|---|
| **Feature to be Tested** | **Group: B** | **Purpose/Comments** |
| • Load Flow Analysis<br>• Economic Dispatch | Simulating the dispatch function on the two modeled circuits starting from the maximum PV and CES deployed at every block | Dispatch energy and resources (including DER and imports from the utility) to achieve minimum cost while connected to the grid |
| | | |
| | | Dispatch functionality of the GMC is tested to achieve increased reliability, efficiency and reduced emissions. |
| | | |
| | | • The various technologies to be added as DER to the circuits under study- Solar PV and battery energy storage<br>• The various smart grid technologies to further enhance controllability of the assets-Controller at the substation, energy storage units capable of communicating with a central controller<br>• The maximum DER/renewable penetration that the circuits can handle- Will be established in these tests<br>• The impacts of DER on the distribution circuit if the maximum penetration is surpassed- will be established in these tests<br>• Viable future scenarios to be further assessed using modeling- the viability of these scenarios will be determined both by the tests and post-processing of the results |
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| ☐ **Continued** | | |

| TEST PROCEDURE SPECIFICATION | **TP#:** B-2 |
|---|---|
| | **Name:** Energy Storage, CES |

**Purpose** Dispatch available resources to meet the demand of the circuit at minimum costs with maximum PV penetration and CES units deployed across the circuits

**Procedure steps**

Log

**Setup**

(1) Select operating condition (electricity load, time of year to determine PV availability)
(2) A CES is modeled corresponding to each transformer
(3) Maximum PV determined in previous simulations (PV) exist on the circuit ($PV_{MAX,A}$)
(4) Select initial condition (SOC of the battery energy storage at the beginning of the simulation)
(5) The circuits are connected to the grid
(6) The GMC is simulated at the substation in OPAL-RT
(7) All node voltages, currents, and frequencies;; load and source real and reactive powers; protection device status are recorded

**Start**

1) Initialize the system with the controller simulated in OPAL-RT
2) Define the rate schedule for electricity not generated by DER (SCE rate)
3) Define the roundtrip efficiency of the CES
4) The controller determines how to respond to the current load and dispatch resources and determines charge/discharge rate and duration for CES
5) Verify that the resources respond to the signal and power is dispatched, and the CESs respond accordingly
6) Tabulate the results, and costs
7) Increase the PV penetration by 5% and repeat the steps 1 through 7
8) Repeat the test for different initial and operating conditions

**Metrics**

1) Cost of generation ($/kWh)
2) (Maximum Transient Voltage – Nominal Voltage)/ Nominal Voltage

☐ **Continued**

| After the test |
| --- |
| 1) Determine the maximum PV penetration achievable for the system with the addition of energy storage ($PV_{MAX,B2}$)<br>2) Determine the impacts on the system when the PV penetration surpasses the threshold established and compare the constraints to Group A, and B-1<br>3) Calculate the emissions and compare to the Base Case and the CA grid, as well as previous scenarios<br>4) Determine if the new maximum PV penetration is physically feasible to install. After establishing the capacity of the PV, it will be determined it there is sufficient roof space and other open spaces on the circuits to install this much PV<br>5) Verify that the cost is indeed the mimum cost (verify that the results is not a local optimum by repeating the test as suggested in step 8 with different initial conditions) |
| **Success criteria**<br>1) The electricity demand is met<br>2) Most economic condition is met<br>3) The voltage at the PCC (for the purpose of this project, it is where the circuits connects to the grid at the substation) remains in the acceptable range |

## Template A-5: Energy Storage Scenarios, Substation Battery

| TEST CASE SPECIFICATION | | TP#: B-3 <br> Name: Energy Storage, Substation Battery |
|---|---|---|
| **Feature to be Tested** | **Group: B** | **Purpose/Comments** |
| • Load Flow Analysis <br> • Economic Dispatch | Simulating the dispatch function on the two modeled circuits starting from the maximum PV and a battery at the substation | Dispatch energy and resources (including DER and imports from the utility) to achieve minimum cost while connected to the grid |
| | | |
| | | Dispatch functionality of the GMC is tested to achieve increased reliability, efficiency and reduced emissions. |
| | | |
| | | • The various technologies to be added as DER to the circuits under study- Solar PV and battery energy storage <br> • The various smart grid technologies to further enhance controllability of the assets-Controller at the substation, energy storage units capable of communicating with a central controller <br> • The maximum DER/renewable penetration that the circuits can handle- Will be established in these tests <br> • The impacts of DER on the distribution circuit if the maximum penetration is surpassed- will be established in these tests <br> • Viable future scenarios to be further assessed using modeling- the viability of these scenarios will be determined both by the tests and post-processing of the results |
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| ☐ **Continued** | | |

| **TEST PROCEDURE SPECIFICATION** | **TP#:** B-3 |
|---|---|
| | **Name:** Energy Storage, Substation Battery |

**Purpose** Dispatch available resources to meet the demand of the circuit at minimum costs with maximum PV penetration and a battery deployed at the substation to support the operation of the distribution system

**Procedure steps**

Log

**Setup**

(1) Select operating condition (electricity load, time of year to determine PV availability)
(2) A battery energy storage is modeled at the substation
(3) Maximum PV determined in previous simulations (PV) exist on the circuit ($PV_{MAX,A}$)
(4) Select initial condition (SOC of the battery energy storage at the beginning of the simulation)
(5) The circuits are connected to the grid
(6) The GMC is simulated at the substation in OPAL-RT
(7) All node voltages, currents, and frequencies;; load and source real and reactive powers; protection device status are recorded

**Start**

1) Initialize the system with the controller simulated in OPAL-RT
2) Define the rate schedule for electricity not generated by DER (SCE rate)
3) Define the roundtrip efficiency of the battery and its operating parameters
4) The controller determines how to respond to the current load and dispatch resources and determines charge/discharge rate and duration for the substation battery
5) Verify that the resources respond to the signal and power is dispatched, and the battery responds accordingly
6) Tabulate the results, and costs
7) Increase the PV penetration by 5% and repeat the steps 1 through 7
8) Repeat the test for different initial and operating conditions

**Metrics**

1) Cost of generation ($/kWh)
2) (Maximum Transient Voltage – Nominal Voltage)/ Nominal Voltage

☐ **Continued**

| After the test |
|---|
| 1) Determine the maximum PV penetration achievable for the system with the addition of energy storage ($PV_{MAX,B3}$)<br>2) Determine the impacts on the system when the PV penetration surpasses the threshold established and compare the constraints to Group A, B-1, and B-2<br>3) Calculate the emissions and compare to the Base Case and the CA grid, as well as previous scenarios<br>4) Determine if the new maximum PV penetration is physically feasible to install. After establishing the capacity of the PV, it will be determined it there is sufficient roof space and other open spaces on the circuits to install this much PV<br>5) Verify that the cost is indeed the mimum cost (verify that the results is not a local optimum by repeating the test as suggested in step 8 with different initial conditions)<br>• |
| **Success criteria** |
| 1) The electricity demand is met<br>2) Most economic condition is met<br>3) The voltage at the PCC (for the purpose of this project, it is where the circuits connects to the grid at the substation) remains in the acceptable range |

## Template A-6: Demand Response Scenarios, HVAC and Smart Appliances

| TEST CASE SPECIFICATION | | TP#: C-1<br>**Name:** Demand Response, HVAC and smart Appliances |
|---|---|---|
| **Feature to be Tested** | **Group: C** | **Purpose/Comments** |
| • Load Flow Analysis<br>• Economic Dispatch | Simulating the dispatch function on the two modeled circuits starting from the maximum PV and various battery scenarios, as well as controllable loads | Dispatch energy and resources (including DER, controllable loads, and imports from the utility) to achieve minimum cost while connected to the grid<br><br>Dispatch functionality of the GMC is tested to achieve increased reliability, efficiency and reduced emissions. |
| | | • The various technologies to be added as DER to the circuits under study- Solar PV and battery energy storage<br>• The various smart grid technologies to further enhance controllability of the assets-Controller at the substation, energy storage units capable of communicating with a central controller, and energy management system<br>• The demand response strategies to further optimize the operations. These include the rate and incentives<br>• Viable future scenarios to be further assessed using modeling- the viability of these scenarios will be determined both by the tests and post-processing of the results |
| | | |
| ☐ **Continued** | | |

| **TEST PROCEDURE SPECIFICATION** | **TP#:** C-1 |
|---|---|
| | **Name:** Demand Response, HVAC and smart Appliances |

**Purpose** Dispatch available resources to meet the demand of the circuit at minimum costs with controllable loads (HVAC and smart appliances), maximum PV penetration and various battery scenarios

**Procedure steps**

Log

**Setup**

(1) Select operating condition (electricity load, time of year to determine PV availability)
(2) Battery scenario: RESU, PV Penetration: $PV_{MAX,B1}$
(3) Select initial condition (SOC of the battery energy storage at the beginning of the simulation)
(4) The circuits are connected to the grid
(5) The GMC is simulated at the substation in OPAL-RT
(6) All node voltages, currents, and frequencies;; load and source real and reactive powers; protection device status are recorded

**Start**

1) Initialize the system with the controller simulated in OPAL-RT
2) Define the rate schedule for electricity not generated by DER (SCE rate)
3) Define the rate, compensation, and program associated with demand response
4) Define the roundtrip efficiency of energy storage
5) The controller determines how to respond to the current load and dispatch resources and controllable loads
6) Verify that the resources respond to the signal and power is dispatched, and the energy storage responds accordingly
7) Verify that the controllable loads responds to the signal and reduce/increase
8) Tabulate the results, and costs
9) For the following two situation repeat step 1 through 8
   a) Battery scenario: CES, PV Penetration: $PV_{MAX,B2}$
   b) Battery scenario: substation battery, PV Penetration: $PV_{MAX,B3}$
10) Repeat the test for different initial and operating conditions
   •

**Metrics**

1) Cost of generation ($/kWh)
2) (Maximum Transient Voltage – Nominal Voltage)/ Nominal Voltage

☐ **Continued**

| After the test |
|---|
| 1) Calculate the emissions and compare to the Base Case and the CA grid, as well as previous scenarios<br>2) Discuss the benefits of demand response to the grid as well as customers<br>3) Verify that the cost is indeed the mimum cost (verify that the results is not a local optimum by repeating the test as suggested in step 10 with different initial conditions) |
| **Success criteria**<br>1) The electricity demand is met<br>2) Most economic condition is met<br>3) The voltage at the PCC (for the purpose of this project, it is where the circuits connects to the grid at the substation) remains in the acceptable range<br>4) Demand response targets set by the controller are met<br>• |

## Template A-7: Demand Response Scenarios, PEV

| TEST CASE SPECIFICATION | | TP#: C-2<br>Name: Demand Response, PEVs |
|---|---|---|
| **Feature to be Tested** | **Group: C** | **Purpose/Comments** |
| • Load Flow Analysis | Simulating the dispatch function on the two modeled circuits starting from the maximum PV and various battery scenarios, as well as controllable loads | Dispatch energy and resources (including DER, controllable loads, and imports from the utility) to achieve minimum cost while connected to the grid |
| • Economic Dispatch | | |
| | | |
| | | |
| | | |
| | | Dispatch functionality of the GMC is tested to achieve increased reliability, efficiency and reduced emissions. |
| | | |
| | | |
| | | |
| | | • The various technologies to be added as DER to the circuits under study- Solar PV and battery energy storage<br>• The various smart grid technologies to further enhance controllability of the assets-Controller at the substation, energy storage units capable of communicating with a central controller, and energy management system, vehicles chargers communicating with the controller<br>• The demand response strategies to further optimize the operations. These include the rate and incentives<br>• Viable future scenarios to be further assessed using modeling- the viability of these scenarios will be determined both by the tests and post-processing of the results |
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| ☐ **Continued** | | |

| **TEST PROCEDURE SPECIFICATION** | **TP#:** C-2 |
|---|---|
| | **Name:** Demand Response, PEVs |

**Purpose** Dispatch available resources to meet the demand of the circuit at minimum costs with controllable loads (PEVs in addition to HVAC and smart appliances), maximum PV penetration and various battery scenarios

**Procedure steps**

Log

**Setup**

(1) Select operating condition (electricity load, time of year to determine PV availability)
(2) An EVCS is modeled at each household
(3) Battery scenario: RESU, PV Penetration: $PV_{MAX,B1}$
(4) Select initial condition (SOC of the battery energy storage at the beginning of the simulation, SOC of PEVs and the charge they require at the end of the charging session)
(5) The circuits are connected to the grid
(6) The GMC is simulated at the substation in OPAL-RT
(7) All node voltages, currents, and frequencies;; load and source real and reactive powers; protection device status are recorded

**Start**

1) Initialize the system with the controller simulated in OPAL-RT
2) Define the rate schedule for electricity not generated by DER (SCE rate)
3) Define the rate, compensation, and program associated with demand response
4) Define the roundtrip efficiency of energy storage
5) The controller determines how to respond to the current load and dispatch resources and controllable loads
6) Verify that the resources respond to the signal and power is dispatched, and the energy storage responds accordingly
7) Verify that the controllable loads (including PEVs) responds to the signal and reduce/increase
8) Tabulate the results, and costs
9) For the following two situation repeat step 1 through 8
    a) Battery scenario: CES, PV Penetration: $PV_{MAX,B2}$
    b) Battery scenario: substation battery, PV Penetration: $PV_{MAX,B3}$
10) Repeat the test for different initial and cooperating conditions
    •

☐ **Continued**

**Metrics**

1) Cost of generation ($/kWh)
2) (Maximum Transient Voltage – Nominal Voltage)/ Nominal Voltage

| After the test |
|---|
| 1) Calculate the emissions and compare to the Base Case and the CA grid, as well as previous scenarios<br>2) Discuss the benefits of demand response and smart charging to the grid as well as customers<br>3) Verify that the cost is indeed the mimum cost (verify that the results is not a local optimum by repeating the test as suggested in step 10 with different initial conditions)<br>• |
| **Success criteria**<br>1) The electricity demand is met<br>2) The voltage at the PCC (for the purpose of this project, it is where the circuits connects to the grid at the substation) remains in the acceptable range<br>3) Demand response targets set by the controller are met<br>4) PEVs have sufficient charge at the end of the simulation<br>5) Most economic condition is met |

## Template A-8: Circuit-Independent

| **TEST CASE SPECIFICATION** | | **TP#:** D<br>**Name:** Circuit-Independent |
|---|---|---|
| **Feature to be Tested** | **Group: D** | **Purpose/Comments** |
| • Load Flow Analysis<br>• Dispatch while islanded | Simulating the dispatch function on the two modeled circuits starting with a fuel cell at the substation to simulate steady-state operation while islanded (circuit-independent) | Dispatch energy and resources (including DER, controllable loads, and imports from the utility) to achieve minimum cost while connected to the grid |
| | | |
| | | Dispatch functionality of the GMC is tested to achieve increased reliability, efficiency and reduced emissions in a simulated islanded mode. Dispatch while islanded |
| | | |
| | | • The various technologies to be added as DER to the circuits under study- fuel cell in addition to other DERs in previous scenarios<br>• The various smart grid technologies to further enhance controllability of the assets-Controller at the substation, energy storage units capable of communicating with a central controller, and energy management system, vehicles chargers communicating with the controller<br>• The demand response strategies to further optimize the operations. These include the rate and incentives<br>• Viable future scenarios to be further assessed using modeling- the viability of these scenarios will be determined both by the tests and post-processing of the results |
| | | |
| ☐ **Continued** | | |

| **TEST PROCEDURE SPECIFICATION** | **TP#:** D |
|---|---|
| | **Name:** Circuit-Independent |

**Purpose** Dispatch available resources to meet the demand of the circuit with only DER (including the fuel cell) and controllable loads

**Procedure steps**

Log

**Setup**

(1) Select operating condition (electricity load, time of year to determine PV availability)
(2) An EVCS is modeled at each household
(3) A fuel cell is modeled at the substation
(4) Battery scenario: RESU, PV Penetration: $PV_{MAX,B1}$
(5) Select initial condition (SOC of the battery energy storage at the beginning of the simulation, SOC of PEVs and the charge they require at the end of the charging session)
(6) The GMC is simulated at the substation in OPAL-RT
(7) All node voltages, currents, and frequencies;; load and source real and reactive powers; protection device status are recorded

**Start**

1) Initialize the system with the controller simulated in OPAL-RT
2) Define the rate, compensation, and program associated with demand response
3) Define the roundtrip efficiency of energy storage
4) The controller determines how to respond to the current load and dispatch resources and controllable loads to fully meet the demand of the system without any import from utility
5) Verify the operation of the fuel cell
6) Verify that the resources respond to the signal and power is dispatched, and the energy storage responds accordingly
7) Verify that the controllable loads (including PEVs) responds to the signal and reduce/increase
8) Tabulate the results, and costs
9) For the following two situation repeat step 1 through 8
   a) Battery scenario: CES, PV Penetration: $PV_{MAX,B2}$
   b) Battery scenario: substation battery, PV Penetration: $PV_{MAX,B3}$
10) Repeat the test with different initial and operating conditions
    •

☐ **Continued**

**Metrics**

1) (Maximum Transient Voltage – Nominal Voltage)/ Nominal Voltage
•

| After the test |
|---|
| 1) Calculate the emissions and compare to the Base Case and the CA grid, as well as previous scenarios<br>2) Discuss the increase in reliability and resiliency<br>3) If the demand cannot be fully met, determine the required capacity to be added and repeat the test |
| **Success criteria**<br>1) The electricity demand is met without import from the utility (i.e. only with DERs and controllable load)<br>2) The voltage at the PCC (for the purpose of this project, it is where the circuits connects to the grid at the substation) remains in the acceptable range<br>• |

# APPENDIX B: Interconnection/Market Overview

## Generator/Resource Interconnection Overview

This section provides an overview of the generator interconnection processes in Southern California Edison (SCE) territory. Understanding these processes requires some background in the electric power system and its market structure, as well as in the procedural requirements for such interconnections.

In the past, Investor Owned Utilities (IOU) such as SCE were vertically integrated monopolies, owning and responsible for all generation, transmission, and distribution assets, as well as for metering, crediting and billing retail customers. The IOUs were (and are) regulated by the California Public Utilities Commission (CPUC). Under what has been called deregulation, the generation business was largely removed from the monopoly and opened to competition. Many functions which were previously internal coordinated activities at SCE such as generation and transmission planning had to be transitioned to open market based processes overseen by either the CPUC or the newly created California Independent System Operator (CAISO). The CAISO operates the transmission systems owned by SCE, PG&E, SDG&E, and Nevada's VEA. The CAISO borders define one Control Area (CA) in the Western Interconnect for which CAISO is the Balancing Authority (BA). A BA is responsible to manage internal load and generation so as to maintain the scheduled power interchanges at its Points of Interconnection (POI) to other CAs, such as LADWP. These power interchanges are scheduled on an hourly step-change basis.

Retail customers are served by Load Serving Entities (LSE) including, in the CAISO area, the three Investor Owned Utilities (IOU) PG&E, SCE and SDG&E, some 24[46] Energy Service Providers (ESP) and by Community Choice Aggregators (CCA)[47]. Each LSE is required by the CPUC to prove they have under contract sufficient generating capacity for Resource Adequacy (RA) which is defined as 115% of their Load Forecast on a 1 in 2 year basis. In addition, they must procure energy to meet their actual load on an economic basis. Most of these RA and energy needs are obtained via bilateral contracts (following an open RFO solicitation) and the remainder are obtained on the market operated by the CAISO. Each LSE submits both an annual and a Long Term Procurement Plan (LTPP) to the CPUC to prove they meet these and other requirements.

[46] https://apps.cpuc.ca.gov/apex/f?p=511:1:

[47] http://www.cpuc.ca.gov/general.aspx?id=2567

A capacity contract (satisfying RA requirements) pays the generator for having, for example, 100 MW of deliverable capacity online at a given time, and pays them a certain rate for energy actually delivered during that time. However the LSE may actually buy the energy it uses during that time from a more economic generator, or from a renewable generator to meet its RPS requirements, meaning that our RA generator with 100 MW capacity available may be delivering substantially less power during that time. At the same time, LSEs may prefer energy contracts with generators able to meet RA requirements. Being a more-or-less free market process, a wide variety of purchase contracts can exist.

The CAISO market defines generator power delivery as occurring at "Pricing Nodes" or PNodes which are substations at which transmission becomes distribution. Load is priced at an energy weighted average of all the delivery nodes of the LSE. The price of power offered at one of these Pnodes must include three components: (1) power delivered at the PNodes, (2) $I^2R$ losses caused by the power exchange, and (3) a charge related to transmission system congestion occasioned by the power exchange in question. This method puts remote and local resources on an even playing field. The whole market scheme is based on the concept of Locational Marginal Price (LMP). If there was no transmission congestion and any buyer could access any seller, then the LMP would be the same everywhere (neglecting the $I^2R$ losses which are small). However, transmission limits prevent the next cheapest available power from getting just anywhere on the grid. The LMP reflects the cost of the next MWh at a given node when that power is provided with a generator dispatch that results in the lowest overall system cost, consistent with system physical constraints and security requirements and thus the terms "security-constrained unit commitment" and "security constrained economic dispatch (SCED)".

The CAISO area is divided into ten local areas (Figure B-1) based on significant transmission constraints between major pockets of load. A portion of the RA procured by the LSEs must be within these local areas due to transmission constraints as determined by the CAISO conservatively based on a 1 in 10 year load with certain transmission contingencies. That portion is referred to as Local Capacity Requirement (LCR).

California is, in general, a net importer of power, and the capacity of the interchanges to other BAs and other states is allocated to the LSEs for purposes of meeting their RA requirements from generators outside of CAISO.

**Figure B-1: CAISO's Local Areas**


Source: California Independent System Operator, 2019 Local Capacity Area Technical Study (https://www.caiso.com/Documents/2019LocalCapacityRequirementsFinalStudyManualdocx.pdf)

Generators count for RA based on their Net Qualifying Capacity (NQC) which includes transmission deliverability, "technical factors" for renewables, performance history and other factors.

In addition to the energy and RA markets of the LSEs, the CAISO identifies and determines the quantity of ancillary services (AS) required for reliability[48] and the AS

[48] CAISO reliability requirements comply with those of NERC, WECC and the NRC.

Regions in which they must be located. Scheduling Coordinators (SC) for each LSE may either procure their required AS or the CAISO will do it for them and bill them. Ancillary Service Products are described in CAISO Tariff section 8 and briefly described in Table B-1

**Table B-1 Ancillary Services in CAISO**

| Service | Description |
|---|---|
| Regulation Up and Down | Real energy resources which respond the AGC signals to maintain frequency and scheduled power exchange at the CAISO interchange boundaries. |
| Spinning Reserves | On line reserve capacity for loss of generation contingency. |
| Non-spinning Reserves | Quick starting capacity to replace/supplement spinning reserve. |
| Voltage Support | First, loads must maintain Power Factor between .97 lag and .99 lead, and generators must maintain voltage schedules per their GIAs. Second, CAISO may procure Reliability Must Run (RMR) contracts for more var support. Third, generators may be required to produce vars beyond their GIA requirement (and be compensated only if they must reduce real power output to do so.) |
| Black Start | Generators are paid to maintain black start capability subject to scheduled and unscheduled testing. |

Source: California Independent System Operator (http://www.caiso.com/Documents/Section8_AncillaryServices_asof_Aug15_2016.pdf)

## Technical Requirements for Interconnection

Technical requirements for interconnection at all levels of SCE's grid are contained in the Interconnection Handbook.[49] (The Handbook satisfies the requirement for a Facility Connections Requirements document contained in NERC Standard FAC-001 Facility Connection Requirements.) The Handbook addresses protection, grounding, anti-islanding, metering, and communications requirements. It also addresses physical things like access to certain equipment by utility personnel and signage. It does not address commercial issues or the administrative processes for such connections.

In general, generators above 1 MW must have SCADA connection using an RTU and a single communications path such as a leased T1 connection. Communication to support protection or Special Protection Systems (SPS) must have two independent fiber optic

[49] Southern California Edison. https://www.sce.com/wps/wcm/connect/348e4d71-5c2a-431f-bf78-16267486fdc9/Interconnection%2BHandbook_1483725988_1485215238.pdf?MOD=AJPERES

lines to the SCE point of connection. These can also support the required SCADA communications.

## Procedures for Interconnecting Generators to SCE's Grid

A generator seeking an interconnection is called an Interconnection Customer (IC) who makes an Interconnection Request (IR) to receive Interconnection service (IS) via Interconnection Facilities (IF) under a Generator Interconnection Agreement (GIA). An IR from an IC traditionally results in a study process to determine the impact of the interconnection on the system and the facilities necessary to make a safe interconnection and mitigate such impacts. The study process will to ensure an adequate but not excessive level of study for the particular IR.

In California and most states, the grid is divided into a distribution system under state jurisdiction (CPUC) for serving retail customers and a transmission system under federal jurisdiction (FERC) for interstate commerce in wholesale bulk power. The subtransmission system may fall into either category depending on whether it creates a parallel path to the transmission system or a separate system just for distribution to customers. SCE's subtransmission system is almost all part of CPUC jurisdiction while PG&E and SDG&E's subtransmission systems are predominantly FERC/CAISO jurisdictional.

Generator interconnection processes depend on which part of the system the connection is made and to whom the power is sold. In SCE territory there are three major processes:

A. The CAISO TOT GIDAP for connection to the transmission system for wholesale power
B. The SCE WDAT GIP for connection to the distribution or subtransmission system for wholesale power
C. SCE Rule 21 for connection to the distribution or subtransmission system for self-generation or for Net Energy Metering at any voltage level

These three processes are discussed in the following sections.

### CAISO TOT

Connecting to the SCE's FERC jurisdictional CAISO controlled transmission grid for purposes of sale on FERC Jurisdictional CAISO market is governed by the CAISO Transmission Owner's Tariff (TOT). Appendix DD Generator Interconnection and Deliverability Allocation Procedure (the GIDAP)[50] describes this in details.

[50] California Independent System Operator. http://www.caiso.com/Documents/AppendixDD_GeneratorInterconnection_DeliverabiltyAllocationProcessDec19_2014.pdf

As shown in Figure B-2, the process of interconnection to the CAISO grid is divided into four phases: (1) The Interconnection Request, (2) The interconnection Study, (3) The Generator Interconnection Agreement, and (4) New Resource Implementation.

**Figure B-2 CAISO Interconnection Process Overview**


Source: California Independent System Operator.
http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx

For transmission level interconnection, four tracks are available within this process: (1) The Queue Cluster Process, (2) The Independent Study Process, (3) The Fast Track Process, and (4) the 10 kW Inverter Process. Their applicability is provided in Table B-2.

**Table B-2: Tracks within the TOT interconnection process**

| Track | Submit IR | Applicable to | Length |
|---|---|---|---|
| Queue Cluster | In April | All | 28 months |
| Independent Study | Anytime | Electrically independent of other generators | 8 months for EO |
| Fast Track | Anytime | <=5MW | 10 weeks |
| 10 kW Inverter | Anytime | 10 kW Inverters with UL 1741 | 10 weeks |

Source: California Independent System Operator.
http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx

A comparison of the timelines associated with the three tracks is given in Figure B-3 below. (The 10 kW Inverter process is a subset of the Fast Track.) Note that throughout the various processes, there are requirements for financial security postings to make sure the IR remains real and to fund ongoing study activity. Similarly, there are requirements to show “Site Exclusivity” meaning the generator has the right to build on a site, and similar showings of progress.

**Figure B-3: Interconnection Timelines Summary**

Cluster – Two+ years

| Cluster 9 Application | Scoping Meeting | Phase I Study | Phase I Meeting | 1st Posting | Phase II Study | Phase II Meeting | Transmission Plan Deliverability | 2nd Posting | Reassessment Result |
|---|---|---|---|---|---|---|---|---|---|
| Apr 2016 | May – Jun 2016 | Jul – Dec 2016 | Jan 2017 | Mar 2017 | May – Nov 2017 | Dec 2017 | Mar 2018 | May 2018 | Aug 2018 |

Independent Study Process (ISP) – Eight months without deliverability

| ISP Application | Electrical Independence | Scoping Meeting | Systems Impact and Facilities Study | Results Meeting | 1st Posting | Reassessment Result |
|---|---|---|---|---|---|---|
| Anytime | 30 CD from ISP eligibility | Set date within 5 BD of Electrical Independence | <= 120 CD of Study Agreement | <= 20 BD of Study Results | <= 120 CD of Study Results | Aug Annually |

Fast Track (FT) – 10 weeks or more

| FT Application | Initial Review (Screens) | Customer Options Meeting | Supplemental Review |
|---|---|---|---|
| Anytime | 15 BD from FT Eligibility | 10 BD from Determination of Upgrades / Additional Studies Needed | 10 BD from Receipt of Review Deposit |

Source: California Independent System Operator. Interconnection Application Options and Process. https://www.caiso.com/Documents/1-2018InterconnectionApplicationRequirements-Options.pdf

The main difference between these tracks is the degree of study required. In general, every generator impacts the common grid and may contribute to the need for grid upgrades. This leads to the need for IRs to be studied together which has led to the Cluster study process as the default way of performing the required studies. If, however, a particular generator can demonstrate "Electrical Independence" as to reliability and local deliverability concerns, it may be interconnected as an Energy Only generator under the Independent Study Process (ISP). If Full or Partial Deliverability Status is desired, that will be assessed later as part of the Cluster Study then in progress. The Fast Track and 10 kW Inverter tracks are limited to small EO generators.

*Deliverability Status*

An understanding of interconnection requires an understanding of "Deliverability Status." Generators may have one of three Deliverability Status designations: Full Capacity, Partial Capacity, or Energy Only (**EO**). Only generators with full or partial deliverability status may participate in the capacity (RA) market. Any generator can participate in the energy market.

"Deliverability" refers to the ability of generated power to be delivered to customers over the transmission network. Generators under study may be able to do this with capacity in the existing transmission plan or may require network upgrades. Network upgrades may be classified as driven by reliability concerns, mostly short circuit and stability but also some load flow. Deliverability network upgrade (DNU) is further divided into local (LDNU) and area (ADNU). LDNU involves transmission facilities near the point of interconnection (POI) which are typically overloaded by one or a few generators. ADNU are typically overloads between major CAISO local areas and are driven by contributions of 20 or more generators.

The Transmission Planning Process (TPP) proceeds annually in parallel with the GIDAP resulting in a current Transmission Plan (TP) at all times. This transmission plan includes some excess area delivery capability which is allocated to those ICs whose IR requests full or partial deliverability so as to participate in the capacity market. The allocation is based on the interconnection customer's progress in terms of permitting, financing, and siting.

Because the transmission planning process is repeated annually, there is an opportunity to reassess available TP deliverability every year.

*The Interconnection Request Process*

The forms for making a generator interconnection request under the TOT and submitting associated data can be found in CAISO forms and documents[51]. The preferred method of submitting IRs is via the online Resource Interconnection Management System (RIMS)[52]. The IR application requires fairly extensive technical information about the proposed resource. RIMS is used to track the status of all of the steps involved between application and commercial operation. Once an IR is accepted, it is assigned a queue position. A listing of all IRs by queue position (which does not provide the name of the requesting entity) can be found by searching the CAISO Website for the title "Interconnection Queue" and selecting the document with a title of "ISO Generator Interconnection Queue.

*The Study Process*

The main track involving the most generators is the Queue Cluster study process. The studies include all IRs in the Queue, which is open from April 1 to April 30 each year. Since the overall process takes 28 months, there will be a number of staggered studies going on at any time.

The studies are divided into a Phase I and Phase II. Phase I determines a good faith estimate of IF, a cap on RNU and LDNU costs, and an informational estimate of ADNU costs. Phase I is followed by meetings at which minor changes can be made and at which the IC must choose between Option A and Option B as to ADNU costs if full or partial deliverability status was requested in the IR.

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[51] California Independent System Operator. https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=055cb684-2a53-4a98-9657-40cbd1d87ba2

[52] California Independent System Operator. http://www.caiso.com/Documents/RIMSUserGuide.pdf

"Option A" is a choice to rely on TP capacity allocation, which, if inadequate, drops the interconnection customer to energy only deliverability status. Option B means committing to funding (with eventual repayment via TAC[53]) of their share of the actual cost of ADNU.

If a generator can show that it is electrically independent of other generators such that there will be no sharing of RNU and LDNU, it is eligible for the Independent Study Process (ISP). An ISP Interconnection Request can be submitted at any time. An ISP study consists of a System Impact Study (SIS) and a Facilities Study (FS). (These were the traditional parts of an interconnection study before the Cluster Study approach.) It results in the interconnection customer being assigned EO deliverability status with Full or Partial deliverability, if requested, being rolled into the deliverability assessment of whichever Cluster Study is appropriate based on timing. The normal time for the ISP is 8 months (to EO status) as opposed to 28 months for the Cluster process.

A Fast Track process, including the 10 kW Inverter process, is available for small (5 MW or less) generators and can be accomplished in as little as ten weeks.

*Generator Interconnection Agreement*

The Generator Interconnection Agreement (GIA) follows the format provided in either CAISO Tariff Appendix EE[54] for large generators or FF[55] for small (<20 MW) generators. A draft agreement is then provided to the interconnection customer for negotiations. There is a process for dispute resolution if necessary.

The agreement covers responsibilities of each party for the construction, testing, operation, and maintenance of the generating and interconnection facilities. It formalizes the results of the studies and governs the subsequent physical implementation.

*New Resource Implementation*

The Interconnection Request, Study and Generator Interconnection Agreement are, in a way, just paper. There still needs to be an actual process for connecting the physical generator and making it available for CAISO market operations. The CAISO identifies six "buckets" of required submittals to get to actual synchronous connection to their grid and to the ultimate goal of the Commercial Operation Date (COD). The dates for CAISO

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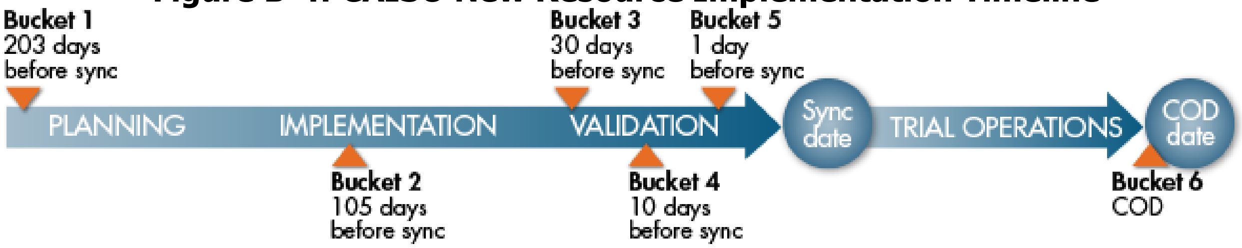
53 The Transmission Access Charge (TAC) is the part of the customer's bill that pays for transmission costs.

54 California Independent System Operator. https://www.caiso.com/Documents/TariffAppendixEE_Nov5_2012.pdf

55 California Independent System Operator. http://www.caiso.com/Documents/AppendixFF_SmallGeneratorInterconnetionAgreement-GIDAP_Dec3_2013.pdf

approval of the buckets are keyed off of the Synchronization Date as shown in Figure B-4.

**Figure B-4: CAISO New Resource Implementation Timeline**




Source: California Independent System Operator.
http://www.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx

The content of these six buckets are summarized as follows:

1. Bucket 1, Full Network Model of the Generator
2. Bucket 2, Regulatory contracts, model testing, and Forecasting information (for wind and solar)
3. Bucket 3, Market preparation
4. Bucket 4, Trial operations approval
5. Bucket 5, Trial operations
6. Bucket 6, COD

**Wholesale Distribution Access Tariff (WDAT)**

Connecting to SCE's CPUC jurisdictional distribution and subtransmission grid for purposes of sale on FERC jurisdictional CAISO market is governed by SCE's Wholesale Distribution Access Tariff (WDAT) which is detailed in Appendix I Generator Interconnection Procedure (the GIP)[56]. With a WDAT, one can interconnect facilities to SCE's distribution system and deliver energy and capacity services to the CAISO-controlled grid, or deliver energy or capacity services from the CAISO controlled grid to their customers.

Interconnection to the CPUC jurisdictional distribution or subtransmission grid for purposes of selling into the wholesale market very closely parallels the process for interconnections to the transmission grid. It is, however, governed by the utility's FERC approved tariff instead of the CAISO's FERC approved tariff. It includes the following additional considerations:

- For purposes of an independent study process (ISP), electrical independence with respect to the distribution grid is also required

[56] Southern California Edison. https://www.sce.com/nrc/openaccess/WDAT/eTariff_Z-WDAT_Attachment_I_5.0.0.pdf

- Distribution upgrades with attendant costs may be required in addition to the other costs in the CAISO tariff
- Includes consideration of distributed generation deliverability for resource adequacy
- There is an option in some cases to choose a Rule 21 generator interconnection agreement

**Rule 21**

Connecting to SCE's CPUC jurisdictional distribution and subtransmission grid for purposes of either self-generation or Net Energy Metering (NEM) is governed by SCE's Rule 21[57].

The CPUC controlled Rule 21 generator interconnection process addresses three areas not considered in the TOT and WDAT processes. These are emergency backup generators, Net Energy Metering (NEM), and self-generation (non-exporting).

*Emergency Backup Generators*

Emergency backup generators either do not operate in parallel with the grid at all or only do so "momentarily" (one second or less) to allow for transfer of loads. Requirements are minimal, mostly to make sure the utilities know of their existence.

*Net Energy Metering*

NEM is allowed for some cases where the generation uses certain preferred renewable power sources and is below a certain size. NEM allows a generator to float on the system, importing and exporting energy as self-generation and load fluctuate. When power flows out into the system the meter "turns backwards" and sells energy to SCE at the same retail rate as SCE sells to the customer. This is a form of subsidy to encourage the deployment of environmentally preferred resources such as solar PV and wind. There are a number of programs under NEM with differing interconnection requirements.

Since the original NEM tariff was seen by some as too generous and shifting too much cost to other customers, a slightly less generous Successor Tariff (ST) was approved by the legislature to replace the original tariff beginning July 1, 2017. The original NEM is often called NEM-1 and the replacement NEM tariff NEM-2. NEM-2 tariffs often have a –ST suffix such as NEM-ST.

There are a large number of variants under the concept of NEM. NEM is most commonly a solar generator at a single customer with a single meter. There is also the concept of Virtual Net Metering (VNM) which allows aggregation under two schemes: NEM-V allows a single owner with multiple metered facilities on adjacent or contiguous land to allocate a single metered generator's output over all the load. MASH-VNM allows

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[57] Southern California Edison. https://www.sce.com/NR/sc3/tm2/pdf/Rule21_1.pdf

similar solar power aggregation for Multifamily Affordable Solar Housing. There is also a provision for military bases allowing a higher MW limit for self-generation with only uncompensated minimal exports. Finally, there is FC-NEM which allowed renewable fuel based fuel cell generation under NEM-1, but for which the door closed January 1, 2015.

A further expansion of the NEM idea is the Renewable Energy Self-generation-Bill Credit Transfer (RES-BCT). This tariff allows the aggregation of bills for a single customer with many non-contiguous properties against a single solar generator, all with separate meters, provided that customer is a local government.

This large number of variations for NEM also resulted in various rules, costs, and limits for interconnection which are tabulated in Rule 21.

*Non-Exporting*

The primary purpose of Rule 21 is for self-generation. That is, generation on the customer side of the meter only to supply part or all of that customer's loads. This generation operates in parallel with the utility such that if the generator is lost, the utility instantly continues to supply the load. Such generation is not allowed to export any power to the utility. This restriction applies to all self-generation not qualifying for NEM because they use non-renewable fuel or because they are too big.

Two ways are recognized to enforce the non export rule:

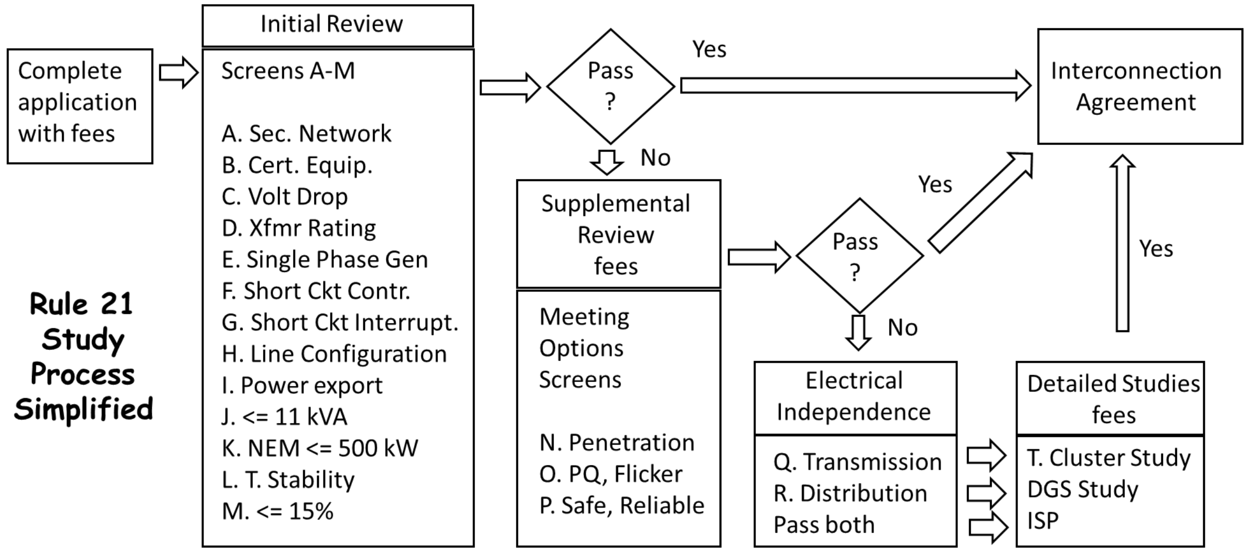
1) Minimum import. In this scheme, the interconnection breaker will trip if imported power drops below a certain level or if reverse power is detected. This scheme does double duty in that it also disconnects the generator from the utility in the event of a fault on the utility system, providing a necessary protection feature.
2) Inadvertent export. This scheme allows up to 60 seconds of inadvertent export to allow some time for the generator to reduce power when site load has suddenly decreased. This allows self-generation to run closer to 100% which is advantageous if self-generated power is cheaper than utility power. However, it also requires a separate protection scheme to clear utility side faults. In some cases this protection scheme can add significant cost.

*Rule 21 Study Process*

The Rule 21 Study Process achieves the same goals as that for the TOT and WDAT tariffs, but is arranged somewhat differently and makes extensive use of screens. A simplified version is presented in Figure B-5 while the more detailed flow chart can be found in the Rule 21 documentation[58]. The Initial Review and (if necessary) Supplemental Review are referred to as the "Fast Track" because, if all screens are passed, the Detailed Studies can be avoided.

[58] Southern California Edison. Rule 21, Generating Facilities Interconnections. https://www1.sce.com/NR/sc3/tm2/pdf/Rule21_1.pdf

**Figure B-5: Rule 21 Study Process Simplified**




Source: UC Irvine

*Smart Inverters*

Early implementation of distributed generation, especially for solar, was governed by Rule 21 and IEEE 1547. Two assumptions behind these documents were that (1) there was urgency to get this distributed generation connected and, (2) total penetration would be limited. With these assumptions, IEEE1547 and Rule 21 were written to require DER to disconnect quickly on any frequency or voltage disturbance and let the existing protection systems do their job. They were also required to not participate in frequency or voltage regulation so as to not end up fighting existing control systems. UL 1741 was written to certify inverters as complying with these requirements to simplify the interconnection studies and process. Anti-islanding protection is required for both UL 1741 and IEEE 1547.

As penetration levels steadily increased, it became apparent that having a large portion of generation disconnect on minor transients was no longer a viable strategy. DERs would have to "ride through" frequency and voltage disturbances. Furthermore, it would be desirable to have the DER actively participate in voltage and frequency regulation. Efforts began to revise Rule 21, IEEE 1547, and UL 1741 to allow for ride through and active regulation, among other features including communication. Inverters certified to meet these new requirements came to be called "smart inverters." All of these efforts remain very much in flux, but the changes fall roughly into three buckets marked by the three phases of the Rule 21 Smart Inverter Working Group (SIWG):

1. Inverter functions not requiring communications. (These requirements are in IEEE 1547a and UL-1741 SA, and are required, with exceptions, for interconnections after September 2017 by California Rule 21 section Hh.)
    a. Frequency and voltage transient ride-through requirements

    b. Active voltage regulation
2. Communications for smart inverters
    a. Expected to require compliance with IEEE 2030.5 (Smart Energy 2.0 protocol)
3. Inverter functions requiring communications (These are the subject of a full revision of IEEE 1547 and further revision of Rule 21, both are in progress
    a. Monitor key DER data
    b. Disconnect and reconnect
    c. Active power limitations
    d. Frequency Watt regulation
    e. Volt Watt regulation
    f. Volt-var regulation
    g. Scheduling

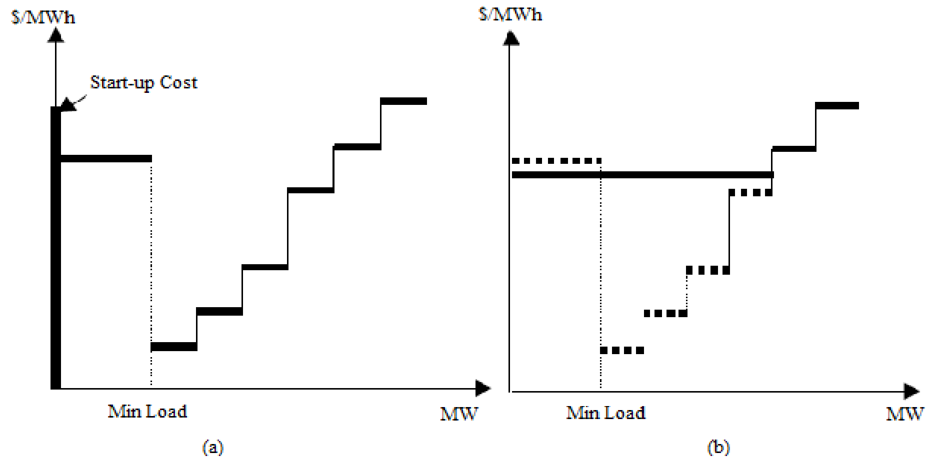
## Electricity Market Fundamentals

The ideal objective of deregulation is to achieve lower costs due to competition introduced by markets. However, electricity is different from other commodities (such as natural gas) because of its physical characteristics that require supply and demand match at each point and instant in the system in the absence of economically viable massive energy storage and considering that even with demand response programs, electricity demand is still quite rigid and does not respond to price signals like other commodities. Thus in practice, the demand curve is largely inelastic. Buyers need a certain amount of electricity for their customers and in the short term at least will accept a wide range of prices. Furthermore, retail consumers of electricity lack information and control to respond to short term changes in price, a condition smart meters and smart grid technology is trying to remedy. Better demand response to price is widely seen as important to the satisfactory functioning of the electricity market.

Energy market is where the competitive trading of electricity occurs. Those who wish to buy or sell power (SCs in the case of the CAISO) submit their bids one day ahead of the actual dispatch into a day-ahead market. Previously, the intersection of the supply and demand curves was declared as the market clearing price (MCP). With the inclusion of congestion, an adjustment would be done to the price in the form of congestion or capacity charge. In a restructured market, the ISO uses a security-constrained unit commitment (SCUC) to clear the day-ahead energy market. The objective of this market is to maximize social welfare while complying with all the physical constraints of the system. In a day-ahead energy market, the bid-in supply is cleared against the bid-in demand. Those generating units cleared, are then committed to participate in the real-time market (thus the term unit *commitment*). In the real-time market, the ISO makes sure that there is enough supply to meet the demand and if not it uses ancillary services to procure more energy.

In some markets, generators are allowed to enter a single bid, while in others such as the CAISO, a multi-bid approach is used which include start-up, minimum load, and energy bids. These energy bids are shown in Figure B-6.

**Figure B-6: Energy Bids (a) Multipart (b) Single-part**




Source: UC Irvine

To ensure supply and demand balance and the reliability of the system, the ISO needs to procure ancillary services. In a deregulated market, however, the ancillary services are procured by the ISO through a competitive market. There are two approaches for settling ancillary services markets: sequential approach, and simultaneous approach. In the sequential approach, the market is cleared for the highest quality service first, then the next highest, and so on until all the reliability requirements are met. The alternative is to clear all ancillary services simultaneously by introducing a rational buyer. In a rational buyer auction, all the ancillary services are cleared together and the substitution of lower quality services with higher quality ones, is done automatically by the ISO.

There are also several methods to pay the cleared generators. One way is to pay them what they had bid in, *pay as bid* pricing. The other option is to pay everyone a uniform price witch is known as *uniform pricing.* In uniform pricing, all providers are paid the market clearing price. In ancillary services markets, there are various options for uniform pricing: marginal pricing, demand substitution, and supply substitution pricing. In marginal pricing, the marginal cost of a service is chosen as its price. In demand substitution pricing, the demand for a lower quality service can be substituted by a higher quality service and the price is set to the highest accepted bid for that service. In a supply substitution pricing, the supply for a higher quality service can be used for a lower quality service and the price is set to the highest accepted bid of that service[59].

## CAISO Markets Overview

Between 1998 and 2001, the CAISO did not allow bilateral contracts by Investor Owned Utilities (IOU) and the majority of the load had to go through the forward spot market which was run by CalPX (California Power Exchange). After the crisis and CalPX being out of business, it was clear that bilateral forward contracts must be allowed to minimize exposure to spot market prices. Today, the majority of the electricity demand in California is served through long-term bilateral contracts. The CPUC requires all LSEs to procure enough capacity to meet 115% of their forecast load. LSEs meet 80-90% of their projected load by means of bilateral contracts with energy suppliers via competitive RFPs. This procurement process has to be open and possibly overseen by a neutral third party monitor. These contracts are for both energy and capacity and consider both economic and non-economic factors. Capacity purchases are based on the supplier's Net Qualifying Capacity (NQC) which considers transmission deliverability and performance track record. The remaining energy and capacity is purchased on the CAISO market in a two-step process consisting of a Day ahead Market (DAM) and a Real Time Market (RTM).

Prior to Market Redesign and Technology Upgrade (MRTU) in April 2009, CAISO balancing area was separated into three zones and the network model used these three zones for market clearing and managing congestion. After MRTU, CAISO adopted a nodal system in which the full network model is solved and the transmission constraints are solved between various nodes on the system. In this new approach, there is no distinction between inter- and intra-zonal congestions, but the competitive and non-competitive paths are distinguished from one another in order to mitigate the local market power, and also provide incentives to invest in congested paths. This distinction is done through introducing the Locational Marginal Pricing (LMP) at each node of the system instead of the previously used zonal pricing.

In DAMs energy, ancillary services, congestion and losses are optimized simultaneously as Integrated Forward Market (IFM), all in one single optimization. After all bids are submitted, and before running the IFM, the CAISO performs a Reliability Requirement Determination and Local Market Power Mitigation in order to validate the bids and make sure that none of the parties are exercising market power and if they are, they will be subject to a bid adjustment. After the IFM, the CAISO performs a reliability run. The generators that have not been cleared in the IFM, are then eligible to participate in the

[59] Razeghi, G. The Development and Evaluation of a Highly-Resolved California Electricity Market Model to Characterize the Temporal and Spatial Grid, Environmental, and Economic Impacts of Electric Vehicles. Ph.D. Dissertation. University of California, Irvine. 2013

Residual Unit Commitment (RUC). The RUC is performed to match the generation with the CAISO forecast of the next day's demand to ensure reliability.

Real-time market (RTM) includes several processed such as Short Term Unit Commitment (STUC) to commit units with medium or short startup requirements, Hour-Ahead Scheduling Process (HASP) which results in an advisory schedule for P-Nodes and firm schedule for import/export to CAISO, Real-time Unit Commitment (RTUC) every fifteen minutes, Security-Constrained Economic Dispatch (SCED) on a five-minute basis, and Real-Time Contingency Dispatch and Exceptional (Manual) Dispatch in case of contingencies and unforeseen occurrences. The details of these processes as well as Full Network Model (FNM) can be found in various CAISO documents and websites some provided in the References section.